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Joint Panel Report
EUB Decision 2004-009

Shell Canada Limited

Applications for an Oil Sands Mine, Bitumen Extraction Plant, Cogeneration Plant, and Water Pipeline in the Fort McMurray Area

February 5, 2004

Joint Review Panel Established by the Alberta Energy and Utilities Board and the Government of Canada

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REPORT OF THE JOINT REVIEW PANEL ESTABLISHED BY THE ALBERTA ENERGY AND UTILITIES BOARD AND THE GOVERNMENT OF CANADA
Decision 2004-009: Shell Canada Limited, Applications for an Oil Sands Mine, Bitumen Extraction Plant, Cogeneration Plant, and Water Pipeline in the Fort McMurray Area
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EXECUTIVE SUMMARY

Shell Canada Limited (Shell) filed Applications No. 1271285, 1271307, and 1271383 with the Alberta Energy and Utilities Board (EUB). Application No. 1271285 was made pursuant to Sections 10 and 11 of the Oil Sands Conservation Act for approval of an oil sands mine, a bitumen extraction plant. Application No. 1271307 was made pursuant to Section 11 of the Hydro and Electric Energy Act for approval of a cogeneration plant. Application No. 1271383 was made pursuant to Part 4 of the Pipeline Act for approval of a fresh water pipeline.

The project would be located approximately 70 kilometres north of Fort McMurray and 10 kilometres east of Fort McKay. It is designed to produce 31 800 cubic metres per day of bitumen product.

The project required an environmental assessment under the Canadian Environmental Assessment Act (CEAA). On June 26, 2003, the federal Minister of Fisheries and Oceans referred the environmental assessment of the project to a review panel. On August 18, 2003, Canada and the EUB entered into an agreement to establish a joint environmental assessment panel (the Panel) for the project. Under the agreement, the Panel was charged with fulfilling the review requirements of both CEAA and the Energy Resources Conservation Act (ERCA).

The Panel considered Applications No. 1271285, 1271307, and 1271383 at a public hearing held in Fort McMurray, Alberta, on October 6 through 10 and October 15, 2003. Participants who provided evidence at the hearing included Shell, other oil sands developers, First Nations, local aboriginal groups, local residents, nongovernment environmental groups, a local medical staff association, and representatives from provincial and federal regulatory agencies. While participants raised a number of issues for the Panel's consideration, most of the issues centred on anticipated environmental and socioeconomic impacts of the project.

Having regard for its responsibilities under ERCA and CEAA, the Panel carefully considered all of the evidence pertaining to the applications. The Panel finds that the project is in the public interest, and the Panel is prepared to approve Applications No. 1271307 and 1271383. The Panel is also prepared to approve Application No. 1271285, subject to the approval of the Lieutenant Governor in Council. Furthermore, the Panel concludes that the project is unlikely to result in significant adverse environmental effects, provided that the mitigation measures proposed by Shell and the recommendations of the Panel are implemented.

In approving Application No. 1271285, the Panel set out conditions relating to mining operations, resource conservation, and tailings management. In addition, the Panel also made recommendations to the federal and provincial governments that would aid in the mitigation of the anticipated environmental effects of the project and would address the need for follow-up measures.

This executive summary is provided for the benefit of the reader and does not form part of the report. All persons making use of the executive summary are reminded that the report should be consulted for all purposes relating to the interpretation and application of the Panel's views.

JACKPINE PROJECT JOINT REVIEW PANEL
Calgary Alberta

SHELL CANADA LIMITED
APPLICATIONS FOR AN OIL SANDS MINE,
BITUMEN EXTRACTION PLANT, COGENERATION
PLANT, AND WATER PIPELINE
FORT MCMURRAY AREA

Decision 2004-009
Applications No. 1271285,
1271307, and 1271383

1 DECISION AND RECOMMENDATIONS TO CANADA AND ALBERTA

Having regard for its responsibilities under the Energy Resources Conservation Act (ERCA) and the Canadian Environmental Assessment Act (CEAA), the joint Canada and Alberta Energy and Utilities Board (EUB/Board) review panel (the Panel) has carefully considered all of the evidence pertaining to the applications and finds that Shell Canada Limited's (Shell's) Jackpine project, Phase 1, is in the public interest for the reasons set out in this report. Under its mandate through the EUB, the Panel is prepared to approve Applications No. 1271307 (the cogeneration plant) and 1271383 (the pipeline). The Panel is also prepared to approve Application No. 1271285 (oil sands mine and bitumen extraction plant), subject to the approval of the Lieutenant Governor in Council. The Panel's approvals are subject to the conditions listed in Appendix 1. The Panel expects that Shell will adhere to all commitments it made during the consultation process, in the application, and at the hearing to the extent that those commitments do not conflict with the terms of any approval or licence affecting the project or any law, regulation, or similar requirement Shell is bound to observe.

With regard to its responsibilities under CEAA and its terms of reference, the Panel concludes that the project is not likely to cause significant adverse environmental effects, provided that the proposed mitigation measures and the recommendations of the Panel are implemented.

The Panel recommends to Canada that

- the Department of Fisheries and Oceans (DFO) collaborate with Alberta Environment (AENV) in the establishment of instream flow needs (IFN) for the Athabasca River in the event that the Cumulative Environmental Management Association (CEMA) fails to meet its timelines (Section 9.6);
- DFO consider IFN objectives and management approaches in its approvals for the project (Section 11.8);
- DFO, in consultation with AENV, Alberta Sustainable Resource Development (ASRD), Environment Canada (EC), and regional stakeholders, require Shell to develop and implement a comprehensive monitoring program relating to fish and benthic macroinvertebrates (Section 12.5);
- DFO require a report from Shell on its monitoring results relating to the compensation lake and share those findings with other stakeholders in the region (Section 12.5);

- EC provide scientific expertise to CEMA working groups in the selection of appropriate indicators of terrestrial and aquatic ecosystems and in establishing effects-based monitoring systems for regional acid deposition (Section 16.2.9);
- DFO consider conditioning its approval to require Shell to participate in CEMA (Section 21.10); and
- Health Canada (HC), in conjunction with Alberta Health and Wellness (AHW), consider undertaking a regional baseline health study primarily dealing with First Nations, Metis, and other aboriginal groups and consider contributing expertise and funding in support of Wood Buffalo Environmental Association's (WBEA's) efforts to implement an ongoing health-monitoring program consistent with the recommendation of the Alberta Oil Sands Community Exposure and Health Effects Assessment Program (Section 24.6).

The Panel recommends to Alberta that

- in AENV's review of Shell's Water Act application, it consider water allocation based on needs of the different project phases (Section 9.6);
- AENV establish IFN for the Athabasca River in collaboration with DFO in the event that CEMA fails to meet its timelines (Section 9.6);
- AENV review the communications programs in place to ensure that regional water quality and water use information is accessible and understandable to interested parties (Section 9.6);
- AENV include a condition in the Environmental Protection and Enhancement Act (EPEA) approval requiring Shell to develop and implement monitoring programs for sediment and water quality for waters that may be affected by the project (Section 10.9);
- AENV ensure that monitoring plans are designed to ensure early detection of potential water quality changes in groundwater and surface water due to their interactions (Section 10.9);
- AENV condition any EPEA approval for the project to require monitoring of acid deposition on water bodies (Section 10.9);
- AENV consider IFN objectives and management approaches in its approvals for the project (Section 11.8);
- ASRD require Shell to also consider the widths and types of buffer zones for benefits to watershed management when evaluating wildlife corridors (Section 11.8);
- AENV require Shell to conduct or support monitoring of water levels in Kearl Lake to validate the predictions made in the environmental impact assessment (EIA) (Section 11.8);
- AENV and ASRD, in consultation with DFO and EC, require Shell to conduct follow-up studies on potential impacts of fish tainting compounds (Section 12.5);
- AENV consider requesting Shell to provide, prior to construction, additional mitigation plans to limit external tailings disposal area seepage (Section 13.1.6);
- AENV's Dam Safety Branch require Shell to include updated seepage modelling results, Quaternary deposits mapping, monitoring plans, and mitigation measures in the tailings disposal area detailed design report (Section 13.1.6);
- AENV incorporate conditions in its approval requiring Shell, in conjunction with other developers, to define and carry out a regional groundwater study of the Pleistocene Channel

aquifer (PCA) in order to evaluate the regional nature of this groundwater resource (Section 13.1.6);

- AENV and ASRD require Shell to participate in a technical review of wildlife corridors that includes analysis of corridor effectiveness in facilitating wildlife movement (Section 16.1.9).
- AENV and ASRD review with Shell an action plan to maintain other islands or strips of undisturbed native vegetation on the Shell lease in association with wildlife corridors (Section 16.1.9).
- ASRD require Shell to develop a wildlife monitoring program for implementation prior to construction (Section 16.1.9);
- ASRD and AENV identify wetlands research as a priority for CEMA to address and that they consider requiring Shell to support a program to facilitate wetlands restoration (Section 16.2.9);
- AENV and ASRD consider whether additional performance criteria should be developed for progressive reclamation (Section 16.3.4);
- AENV monitor end-pit lake (EPL) development and testing by Shell and other operators (Section 16.4.4);
- AENV consider long-term environmental effects on the Muskeg River in the design of Shell's water monitoring programs (Section 17.6);
- AENV develop management plans and objectives for the Muskeg River basin if Muskeg River Watershed Integrity (MRWI) subgroup timelines are not met (Section 17.6);
- in addition to recommendations on IFN and MRWI, AENV and ASRD consider developing management plans or objectives respecting other environmental issues if CEMA timelines are not met (Section 21.10); and
- AHW, in conjunction with HC, consider undertaking a regional baseline health study primarily dealing with First Nations, Metis, and other aboriginal groups and consider contributing expertise and funding in support of WBEA's efforts to implement an ongoing health-monitoring program consistent with the recommendation of the Alberta Oil Sands Community Exposure and Health Effects Assessment Program (Section 24.6).

2 INTRODUCTION

2.1 Applications

Application No. 1271285 was made by Shell pursuant to Sections 10 and 11 of the Oil Sands Conservation Act (OSCA) for approval of an oil sands mine and bitumen extraction facility in the Fort McMurray area. Shell also applied for approval to receive third-party oil sands for processing and to produce and ship oil sands from the site for third-party processing.

Application No. 1271307 was made by Shell pursuant to Section 11 of the Hydro and Electric Energy Act for a cogeneration plant consisting of one 160 megawatt (MW) gas turbine generator to be located in the southeast portion of Section 10 in Township 95, Range 9, West of the 4th Meridian (SE 10-95-9 W4M.).

Application No. 1271383 was made by Shell pursuant to Part 4 of the Pipeline Act for approval of an 8.5 kilometre (km) fresh water pipeline from legal subdivision (LSD) 02-23-95-10 W4M to LSD 08-16-95-10 W4M.

In support of its proposal and as part of its application to the EUB, Shell also submitted an EIA report to AENV, pursuant to EPEA.

The project would be located approximately 70 km north of Fort McMurray and 10 km east of Fort McKay in Township 95, Ranges 8 and 9, West of the 4th Meridian. The project includes the planning, construction, and operation of the following major oil sands facilities:

- open pit, shovel-truck mine designed to produce 31 800 cubic metres per day (m^3/d) of bitumen for 20 years,
- relocatable crushing and conveying system to size and transport the oil sands to an ore preparation plant,
- three bitumen processing trains that would use a warm (40 to 50°C) water-based, caustic-free ore conditioning and extraction process,
- paraffinic solvent-based bitumen froth treatment process,
- thickeners to thicken thin fine tailings and recycle water,
- cogeneration plant,
- fresh water pipeline connecting the existing Muskeg River Mine (see Figure 1) water withdrawal from the Athabasca River to the project,
- infrastructure associated with the mine and related facilities, and
- tailings management scheme.

The project proposal also includes

- an integrated reclamation plan,
- an integrated water management plan,
- the diversion of 63.5 million (10^6) m^3 per year of water from the Athabasca River, with a maximum instantaneous withdrawal rate equal to the permitted capacity of the intake at 4.17 m^3 per second (s),
- waste management plans,
- initial and ongoing consultation with stakeholders on the social, economic, and environmental impacts of the project, and
- a number of agreements.

Figure 1 shows the project location and other features of the area.

2.2 Joint Panel Review Process

Shell applied to DFO for approval under Section 35(2) of the Fisheries Act for authorization to cause the harmful alteration, disruption, or destruction of fish habitat. Prior to DFO issuing an authorization, an environmental assessment of the project under CEAA was required.

On June 26, 2003, the Honourable Robert Thibeault, Minister of Fisheries and Oceans, referred the environmental assessment of the project to a review panel, pursuant to Section 21(b) of CEAA.

On July 30, 2003, the Canadian Environmental Assessment Agency announced that it was proposing to establish a joint environmental assessment panel for the project. Following a 21-day public comment period, the Honourable David Anderson, Minister of the Environment, and Neil McCrank, Q.C., Chairman of the EUB, signed an agreement (see Appendix 2) to establish the Panel.

Under the Panel agreement, the Panel is charged with fulfilling the review requirements of both CEAA and ERCA. Under ERCA, the Panel must determine whether the project is in the public interest. In making this determination, the Panel is required to consider a range of factors, including resource conservation, safety, and the economic, social, and environmental impacts of the project.

Under CEAA, the Panel is required to submit a report to the Minister of the Environment and to the Minister of Fisheries and Oceans providing the Panel's rationale, conclusions, and recommendations relating to the environmental assessment of the project, including any mitigation measures and follow-up programs.

Under its CEAA mandate, the Panel must assess the environmental effects of the project, including the environmental effects of malfunctions or accidents that may occur in connection with the project and any cumulative environmental effects likely to result from the project in combination with other projects or activities that are existing or planned.

Under its CEAA mandate, the Panel must also determine the significance of the environmental effects of the project. In examining whether any potential adverse effects associated with the project are significant, the Panel must consider the magnitude, geographic extent, duration and frequency, degree to which they are reversible or irreversible, and ecological context of those effects.

Under its CEAA mandate, the Panel must also consider whether there are technically and economically feasible measures that would mitigate any significant adverse environmental effects of the project.

This report sets out the Panel's decision, reasons, rationale, conclusions, and recommendations with respect to its review of the project under ERCA and CEAA and includes a discussion of recommended mitigation measures and follow-up programs. This report also provides a summary of comments received from the public.

2.3 Hearing

The Panel consisted of J. D. Dilay, P.Eng. (chair), R. Houlihan, Ph.D., P.Eng., and G. Kupfer, Ph.D. The Panel considered the applications at a public hearing held in Fort McMurray, Alberta, on October 6 through 10 and October 15, 2003.

Those who appeared at the hearing and the abbreviations used in this report are set out in Appendix 3.

Syncrude Canada Limited (Syncrude) participated in the hearing for the purpose of making final argument. Canadian Natural Resources Limited (CNRL) participated in the hearing for the purpose of questioning. UTS Energy Corp., Suncor Energy Limited, and Imperial Oil Resources and ExxonMobil (ExxonMobil) registered at the hearing but did not question or provide final argument.

3 AGREEMENTS

3.1 OSEC and Shell Agreement

The Oil Sands Environmental Coalition (OSEC) stated that it did not object to the project based on its understanding that Shell would manage and mitigate the adverse effects of the project as outlined in the terms and conditions of its agreement with Shell.

OSEC stated that its agreement addressed issues that OSEC believed were priority issues for the project and the cumulative effects of oil sands development. These issues included species at risk, particulate matter, acid deposition, water withdrawals from the Athabasca River, land disturbance, including loss of wetlands, wildlife movement, and habitat, the creation of EPLs, greenhouse gases (GHGs), and impacts on municipal infrastructure, health, traffic safety, housing, and social services.

OSEC noted that the next steps for Shell and OSEC would be to develop an action plan containing specific tasks and schedules required to meet the agreed-upon objectives.

OSEC requested that the Panel take the agreement into consideration in its deliberations. OSEC also requested that the EUB formally recognize the agreement in any approval it might issue for the project.

3.2 MCFN and Shell Agreement

At the opening of the hearing, the Mikisew Cree First Nation (MCFN) stated that it had reached an agreement with Shell. MCFN stated that it no longer objected to the Shell applications and that many of its specific concerns in relation to the EIA and the project had been addressed.

MCFN said that its main concerns about the project related to impacts of the project on the quantity and quality of water in the Athabasca River. MCFN was also concerned about social, economic, cultural, health, and other impacts of the project on its people and traditional lands. MCFN stated that its concerns were addressed in Shell's Environmental Action Plan. In the plan, Shell committed to provide 30 days of on-site water storage and agreed to involve MCFN in the design, implementation, and review of its monitoring and reclamation plans. An agreement was also reached regarding a number of social, economic, and cultural impacts. The agreement included the possibility of Shell funding a health study in Fort Chipewyan. MCFN stated that it and Shell were committed to developing an action plan to ensure the agreement was met.

MCFN stated that it remained concerned about climate change, long-term flows in the Athabasca River, and CEMA's progress towards defining IFN. MCFN presented evidence on these issues at the hearing.

3.3 ACFN and Shell Agreement

The Athabasca Chipewyan First Nation (ACFN) stated that it did not object to the project, based on its understanding that Shell would mitigate the adverse effects of the project as outlined in the terms of the mitigation agreement between ACFN and Shell.

ACFN stated that water was its main concern and that Shell had addressed this concern by agreeing to limit its withdrawal of water from the Athabasca River and to abide by any approved CEMA recommendations on IFN. Shell also agreed that it would not negatively affect Kearl Lake or McLelland Lake.

ACFN noted that the agreement also included a requirement for an ongoing relationship between ACFN and Shell.

ACFN requested that the Panel consider its agreement with Shell in its deliberations. ACFN also requested that the EUB approval specify the EUB's expectations and requirements in relation to those matters described in ACFN's agreement with Shell.

3.4 Fort McKay and Shell Agreement

Fort McKay First Nations and Metis Local 122 (Fort McKay) stated that it did not object to the project, based on its understanding that Shell would manage and mitigate the adverse effects of the project as outlined in the terms and conditions of Fort McKay's agreement with Shell. Fort McKay requested that the Panel carefully consider the issues and the mitigation identified in the agreement. It hoped that the proposed mitigation would be endorsed and facilitated by the EUB and AENV.

3.5 Non-assertion of Rights Agreement

The Province of Alberta and MCFN advised the Panel that they had entered into a Non-assertion of Rights Agreement, in which MCFN agreed not to assert constitutional rights before the Panel. The Province of Alberta agreed that it would not challenge MCFN's claims of traditional occupation of the project lands before the Panel. The agreement allows the Province of Alberta or MCFN to raise those issues in other forums.

3.6 Views of the Panel

The Panel acknowledges and commends Shell, MCFN, ACFN, Fort McKay, and OSEC on the success of their efforts to enter into agreements. While these agreements will not form part of the EUB approval, the Panel does expect Shell to meet its commitments and continue its consultation and communication efforts throughout the life of the project.

4 ISSUES

The Panel considers the issues respecting the applications to be

- purpose, need, and alternatives to the project,
- resource recovery,
- tailings management,
- environmental effects (water, terrestrial, air),
- health effects,
- measures to enhance beneficial environmental effects,
- need for EIA follow-up,
- regional initiatives,
- regional development,
- social and economic effects,
- public consultation,
- capacity of renewable resources, and
- traditional use and cultural resources.

The following sections of the report summarize the evidence of Shell and the interveners and provide the Panel's assessment of the issues. If Shell or an intervener expressed no views on a particular issue, there is no corresponding section for Shell or that intervener in the report.

5 PURPOSE, NEED, AND ALTERNATIVES TO THE PROJECT

5.1 Purpose and Need for the Project

5.1.1 Views of Shell

Shell indicated that its goal was to continue to supply energy in a responsible manner and to be a responsible member of the communities in which it operated. Shell stated that it must remain viable as a corporation to provide a reasonable return to its shareholders and employment for its employees and to continue to support the communities in which it operated.

Shell acquired Lease 13 in 1956 and spent over $250 million in evaluating its resource potential. In 1999, Shell received approval for the Muskeg River Mine and the Scotford Upgrader and spent about $7 billion on the development of those projects. Shell stated that the project was needed to realize the full benefit of Lease 13 reserves.

Shell indicated that the purpose of the applied-for project was to exploit the resource on Lease 13 further and to provide a supply of bitumen to upgrade, refine, and sell oil to the public. According to Shell, there will be an ongoing demand for transportation fuels and other oil products in North America, which Shell will have the opportunity to meet through the development and use of this resource.

Developments such as the project were integral to Shell's long-term success as a fully integrated petroleum company and responsible member of the communities in which it operated. It stated that oil sands provided a secure domestic source of oil to replace diminishing conventional supplies for North America.

Shell stated that it began testing production methods on Lease 13 in 1955 and first applied to the Alberta government in 1962 for approval of an in situ project. This application was withdrawn as mining methods evolved and the Great Canadian Oil Sands (now Suncor) project advanced.

Shell indicated that to achieve economic production using an in situ recovery method, all of the following conditions would have to be met:

- minimum ore grade,
- suitable cap rock,
- sufficient depth, and
- absence of low-permeability zones in one contiguous area.

Shell did not consider locations within the project area to be economically viable for in situ techniques. Therefore, Shell did not pursue in situ extraction processes as an alternative to the project.

As a result, Shell concluded that there were no viable or realistic alternatives to the project. Shell stated that the need to maximize the value of an asset Shell had owned since 1956 and to obtain a source of bitumen supply for upgrading, refining, and selling to the public could be only achieved through the development of the project.

5.1.2 Views of the Panel

The Panel notes that no interveners argued against Shell's stated need and purpose for carrying out the project. The Panel accepts Shell's stated need and purpose and the criteria that Shell used to evaluate the alternatives it identified. The Panel notes that the purpose and need for the project provide the context for the Panel's consideration of alternatives to the project.

The project, as scoped by the signatories to the Panel agreement, is to construct and operate an oil sands mine, bitumen extraction facility, cogeneration plant, and fresh water pipeline. The Panel, having considered the potential alternatives to the project, concludes that it has sufficient information about the need and purpose of the proposed undertaking and that there are no viable alternatives to the project.

5.2 Alternative Means of Carrying Out the Project

5.2.1 Views of Shell

Shell considered a number of alternative means of carrying out the project. It evaluated the following mining, facility, and infrastructure locations and process methods in detail:

- mine opening sequences and locations,
- external tailings disposal locations,

- plant site locations,
- ore preparation methods,
- ore conditioning and bitumen extraction methods,
- froth treatment methods,
- tailings management methods,
- utility corridor locations,
- access road locations, and
- stream diversions.

Shell evaluated three alternatives for a mine opening location and sequence. Alternative 1 had the mining starting in the area closest to the tailings disposal area and plant site and advancing west to east. Alternative 2 considered mining starting from the north side of the lease, east of the north overburden disposal area. Alternative 3 considered mining starting from the northeast corner of the lease. Shell based the comparison of the three alternatives on development sequences for mining that assessed the initial quantity of overburden, quality of oil sands feed, initial capital costs for ore handling and preparation systems, and the sequencing of reclamation material stockpiles (RMS) and overburden disposal areas. Shell chose Alternative 1 because it was a better choice technically, and it deferred a number of stream disturbances to a later date.

Shell applied for an external tailings disposal area on the southeast corner of Lease 13, after it had evaluated six alternative sites. Shell indicated that because Clearwater clays were under some of the southeast site, it would require additional design features to ensure geotechnical stability. Shell stated that the southeast site was constrained by a number of features limiting its expandability. The applied-for location was Shell's preferred alternative for both economic and environmental reasons.

Shell stated that it required a plant site with enough plot space for a three-train bitumen extraction plant. It reviewed four possible locations, all in areas of low economic oil sands potential but reasonably close to the main ore body. Shell applied for the plant site adjacent to and on the east side of Jackpine Creek (Figure 1). This location was the best-ranked alternative in all of the main categories that Shell used to assess possible locations.

With respect to alternatives for ore preparation, Shell applied for the rotary breaker and slurry box approach, on the basis that it was successful at the Muskeg River Mine. Shell considered the options of feeding ore into a mixbox and or into a cyclofeeder, but was unable to obtain detailed cost and performance data to compare those to its applied-for option.

Shell selected an ore conditioning process that used a noncaustic chemical additive with water between 40 and 50°C, mainly because the environmental benefits were greater when compared to processes that used caustic and/or operated at higher temperatures. The slurry also had to be mechanically conditioned in a pipeline, as rotary drum conditioning had not been scaled up to a suitable commercial use and tank conditioning did not appear to have the technical or economic benefits of pipeline conditioning. Shell stated that it did not consider drum conditioning to be a viable "conditioning only," option based on the data gathered.

Shell concluded from its review that the noncaustic selection would not affect the temperature selection. In addition, the noncaustic and temperature selections would not affect which mechanical conditioning was selected. Shell stated that it selected the Muskeg River Mine extraction and ore conditioning process as its preferred alternative because it was the best economically and technically and was only marginally different from the best environmental case.

Shell assessed four alternative froth treatment processes. One was identical to the existing Muskeg River Mine process design. The three other alternatives considered were use of

- a naphtha-based process diluent,
- inclined plate separators instead of countercurrent gravity separation cells, and
- electrostatic desalting to replace one of the steps in froth cleanup.

Shell stated that its assessments of these alternatives were based on previous proprietary Muskeg River Mine selection studies.

Shell noted that the Muskeg River Mine used a paraffinic froth treatment process because that provided the desired product quality. Shell eliminated three other froth treatment alternatives because they did not provide the required product yield or quality.

All of the tailings streams from the extraction and froth treatment area would be deposited in an external tailings disposal area until there was enough space to deposit the streams in-pit. Shell stated that tailings disposal in external containment required different engineering management than in-pit disposal. It evaluated external and in-pit tailings management options separately. It studied a number of tailings management alternatives for external tailings disposal and in-pit disposal.

The tailings management alternatives for external tailings disposal included

- the use of thickeners,
- no use of thickeners, and
- an alternative that used a thickener, with recovery of thin fine tailings (TFT) in the tailings disposal area for thickening.

Although the third alternative ranked higher than the alternative of not using thickeners, the research data for recovery of TFT from the tailings disposal area was too preliminary for that option to be considered. Shell chose the use of thickeners as its preferred alternative because it resulted in a better tailings management scheme with reduced volumes of TFT.

The tailings management alternatives for in-pit tailings disposal included

- mixing sand and all other tailings streams with gypsum,
- mixing sand and all other tailings streams without gypsum, and
- layering and dewatering.

Using gypsum was Shell's preferred choice, while the layering and dewatering alternative ranked second. Shell's review showed that only the sand and gypsum alternative had the required engineering data to support an application case. Shell said that it would carry out research and development using the Muskeg River Mine streams when it moved that mine's tailings in-pit.

Shell studied three utility corridor alternatives for electrical power and water and three for natural gas. Corridor rankings were unaffected by what the corridor would contain, whether natural gas, solvent, power, or water. Shell evaluated three alternatives for the power and water pipeline corridor and determined the best of the three alternatives. The three possible natural gas pipeline corridors were then ranked against the common power and water pipeline corridor. The preferred approach was a corridor that contained all utilities, power, water, and gas and minimized terrestrial disturbance.

Shell studied seven creek diversion alternatives representing the technically viable options for each creek (see Figure 2). The Khahago, Muskeg, Wesukemina, Shelley, Pemmican, Green Stocking, and Blackfly Creeks would be affected in the project area.

Respecting options for creek diversions, Shell chose the alternative of constructing a low dike and surge facility at the headwaters of Khahago Creek to mitigate the effects of precipitation and runoff, even though it was less attractive economically, because it met the stakeholders' needs.

5.2.2 Views of the Panel

The Panel concludes that Shell has provided adequate information on alternative technologies and alternative construction methods for consideration of these alternative means and their environmental effects. Having regard for Shell's comparisons, the Panel accepts shovel-truck mining, noncaustic bitumen extraction, paraffinic froth treatment, an external tailings disposal area, and in-pit disposal of tailings consolidated with the aid of gypsum as the preferred means of carrying out the project. The Panel accepts that there is a need to divert a number of streams in order to access the reserves. The Panel believes that Shell's mine plan and the location of the plant, tailings disposal area, and infrastructure provides a reasonable balance of good engineering and environmental management practices.

6 MINE PLANNING AND RESOURCE CONSERVATION

6.1 Mine Project Area

6.1.1 Views of Shell

Shell stated that the proposed project area extended from the Muskeg River Mine project area to the boundaries of Lease 13. Shell indicated that development activities for the project would occur east of Jackpine Creek and the Muskeg River (Figure 1). Shell included the area west of Jackpine Creek in the proposed project area because it contained corridors for the road access, utilities, and solvent and product pipelines that had not previously been included in the Muskeg River Mine project area. Shell denoted the area between Jackpine Creek and Muskeg River, referred to as the Sharkbite area, as a potential Muskeg River Mine expansion area. Shell stated that Albian Sands Energy Inc. (Albian Sands) would mine the Muskeg River Mine expansion area.

6.1.2 Views of the Panel

The Panel believes that the project area should allow Shell the opportunity to implement the project. The Panel notes that the corridors described by Shell would extend outside of the proposed project area and would be the subject of other applications. Furthermore, although the Panel notes Shell's assurances that an agreement can be struck between it and Albian Sands, the Panel believes that the project area proposed for the Jackpine Mine may impact Albian Sands's ability to maximize resource recovery in the potential expansion area. The Panel finds that the appropriate project area is the area covering the portion of Lease 13 east of Jackpine Creek and Muskeg River, shown in Figure 1.

6.2 Lease Boundary Mining

6.2.1 Views of Shell

Shell stated that the project would be bordered by the Muskeg River Mine to the west, Syncrude Lease 34 to the north, the Crown lease and ExxonMobil Lease 36 also to the north, and the Syncrude Aurora South project to the east and south. Shell indicated that the oil sands ore body extended beyond the Jackpine Mine lease boundary and into Syncrude Aurora South project, Syncrude Lease 34, ExxonMobil Lease 36, and a Crown lease.

Shell noted that there were a number of options to deal with the lease boundary between Syncrude Aurora South Mine and the Jackpine Mine, each necessitating some amount of resource sterilization. Shell stated that its preferred option was to pursue commercial agreements for swapping reserves to reduce or eliminate loss of mineable ore at the lease boundaries. Shell indicated that it was considering several options for ore swapping, but no agreements had yet been reached.

Shell indicated that although mineable oil sands extended beyond the north boundary into other leases, none of those leases had approved or proposed plans for development that would abut Shell's boundary.

Shell proposed that the Muskeg Creek diversion corridor be a 100 m wide corridor along the north lease boundary, primarily on Shell's lease. The Muskeg Creek diversion corridor was included as fish habitat loss compensation in Shell's No Net Loss Plan (NNLP). However, Shell noted that as part of the cooperation agreement with ExxonMobil, Shell would try to optimize resource recovery and that could impact the location of the Muskeg Creek diversion. Shell proposed to construct the diversion in 2018.

Shell stated that it was committed to working with both Syncrude and ExxonMobil to maximize ore recovery along the lease boundary. Shell agreed to submit, five years prior to commencement of mining, a description of how the resource extending beyond its lease boundary would be mined, including the impact on its mining and tailings plan and any project boundary modifications required.

6.2.2 Views of the Panel

The Panel notes that Shell is committed to continuing discussions with ExxonMobil and Syncrude to develop plans for recovering resource along the common lease boundaries. The

Panel commends Shell's efforts to pursue commercial agreements to exchange ore and thereby reduce lease boundary sterilization. The Panel would welcome agreements that result in optimal resource recovery. The Panel believes there is opportunity for Shell and ExxonMobil to optimize the location of the Muskeg Creek diversion to ensure maximum resource recovery. It will require Shell to address the location of the diversion and any associated oil sands sterilization as part of a lease boundary submission.

The Panel believes that lease boundary plans must be in place well in advance of mining to allow for a workable mine plan, including tree clearing, placement of ditches and dewatering of muskeg, location or relocation of infrastructure, and incorporation of material volumes. The Panel finds that submission of mining details and alternatives at least five years prior to commencement of mining at the lease boundary is a prudent course of action. This would allow time to gather additional information and to evaluate the mining alternatives identified. The five-year submission requirement is further justified in the event that leaseholders cannot reach agreement and EUB intervention is required.

The Panel directs that Shell submit a lease boundary report five years prior to mining activities reaching any common lease boundary. The report must include a comprehensive description of the lease boundary geology and reserves, geotechnical conditions, alternative mining scenarios and impacts, and the costs associated with each, all in accordance with Section 3.1 of EUB *Interim Directive (ID) 2001-7: Operating Criteria—Resource Recovery for Oil Sands Mines and Processing Sites.*

6.3 Road Access, Utility Corridors, and Plant Site

6.3.1 Views of Shell

Shell stated that the Canterra Road would be used to access the project. Shell's proposed utility corridors and the Canterra Road cross the Sharkbite area. Shell agreed that there was mineable oil sands in this area; however, it was not applying for development of the Sharkbite area as part of the Jackpine project applications. Shell said that it saw value in recovering the resource in the Sharkbite area and its intent was to ensure that resource recovery was maximized. Shell indicated that additional resource drilling would be completed in the Sharkbite area during the winters of 2003 and 2004, prior to finalizing the infrastructure routes.

Shell stated that the Canterra Road was a private road with multiple owners and that Shell owned the portion of the road within Lease 13. Shell also stated that it was not responsible for regional alternatives to this road. However, Shell stated that it and Syncrude were looking for an acceptable route from Highway 63 to their respective project areas. Shell stated that this route would be located generally along the south edge of Lease 13. Shell also stated that the results of the discussions between it and Syncrude could change the routing of the Jackpine Mine access route. Beginning in 2007, with the proposed start of full construction of the project, a major realignment of the Canterra Road west and north of the project area would be required to allow for continued access to oil sands developments east of Lease 13. For the longer term, the road would be closed in 2010 when mining activities commenced. Shell stated that the Regional Issues Working Group (RIWG) Transportation Subcommittee was exploring a more permanent eastside access corridor.

A marginal pit expansion area, denoted as SH02-537, would encroach on the plant site footprint. Shell's evaluation indicated that area was not economic to mine (Figure 1). However, Shell stated that it would complete additional resource drilling along the pit limits in the area prior to finalizing the footprint limit of the plant site.

6.3.2 Views of the Panel

The Panel notes that additional drilling in the Sharkbite area will provide further understanding of the mineable oil sands zone. It notes that there is a possibility that the current access route may change as a result of Shell and Syncrude working together to find a suitable access route to the project and the Syncrude Aurora South Mine. The Panel also notes that Shell is participating in RIWG's Transportation Subcommittee, which includes other oil sands developers, Alberta Transportation, and the Regional Municipality of Wood Buffalo (RMWB), to find alternatives to the Canterra Road. The Panel further recognizes that significant changes to the Canterra Road will not occur until 2007. Therefore, the Panel believes that the proposed utility corridor and access route could potentially be modified. Those modifications would need to be considered from a number of aspects, including resource recovery.

The Panel believes that there is sufficient time to acquire the information required to optimize the recovery of mineable oil sands in the Sharkbite area and the location of the access road and utility corridor for the project. The Panel, therefore, directs Shell to submit, for EUB approval, an access road and utility corridor update in its 2006 annual report. The report shall include a resource assessment of the oil sands located in the Sharkbite area and under the modified infrastructure corridor. It shall also include a comparison of alternative access road and utility corridor alignments with respect to resource recovery and other relevant criteria.

The Panel believes that the plant site footprint is sufficient for the proposed project. However, the Panel will require Shell to obtain EUB approval should the plant site area need to be larger. The Panel directs Shell to submit, for EUB approval, a resource assessment of the plant site area two years prior to construction.

6.4 Overburden Disposal Areas and RMS

6.4.1 Views of Shell

Shell outlined a number of disposal areas for overburden and similar waste materials that would be required for the life of the project. Shell indicated that it undertook a review of the geotechnical conditions that affect the disposal areas to identify key geotechnical issues that would be addressed during the mine plan development. Shell also stated that it obtained no new data from the field or laboratory for this analysis; it used a database of geotechnical testing results completed at the Muskeg River Mine, supplemented with Suncor and Syncrude operating information. Shell indicated that it would need to complete further site-specific geotechnical investigations prior to construction.

Shell indicated that it would develop the east overburden disposal area first. This area was divided into two parts to provide a haulage corridor from the mine to the in-pit crusher station. The east disposal area generally conformed to the outline of the PCA (see Section 13). According to Shell, the channel had removed up to 50 m of oil sands along its course, and therefore had significantly decreased the amount of mineable resource. Shell completed drilling core and auger holes in 2001/2002 to improve confidence in the aerial extent and base elevation of the PCA. However, Shell stated that it would complete additional drilling in the mining areas surrounding the east overburden disposal area to further define mineable ore and the location of the final pit wall. Shell stated that the final pit wall would optimize mining costs versus impacts to the PCA due to encroachment. Shell agreed to submit this information to the EUB for review and approval, and stated that it would prefer to submit this as part of the annual mine plan one year prior to placement. Shell indicated that depending on the additional drilling, it would be willing to modify the disposal area footprint to avoid placing overburden on mineable oil sands.

Shell stated that the west overburden disposal area was scheduled to accept material in 2013. It noted that all 24 drillholes located within the footprint had total-volume-to-bitumen-in-place ratios (TV:BIP) greater than 12. The west overburden disposal area would be surrounded by three RMS, denoted as 1, 3, and 4. Shell stated that it would do additional drilling in the mining areas to further delineate the pit limit prior to placing material in the RMS. Referring specifically to RMS 3 and 4, Shell indicated that if drilling showed that there was oil sands in this area, it would not place reclamation material on mineable oil sands. Shell said that it would prefer to submit this information to the EUB for review and approval as part of the annual mine plan.

Shell indicated that the north overburden disposal area would be scheduled to accept material in 2018. Shell noted that it would complete drilling in this area five years prior to overburden placement commencing. Shell agreed to complete further drilling within the footprint of the disposal area and submit a resource assessment of the north overburden disposal area to the EUB two years prior to placing material in this area.

Shell agreed that additional drilling may result in changes to the pit limits and agreed to provide additional ore body characterization. Shell indicated that it was willing to submit an updated ten-year mine plan and material balance by 2008.

6.4.2 Views of the Panel

The Panel finds that the preliminary designs used by Shell for the overburden disposal areas are reasonable, based on the currently available information regarding geotechnical characteristics of the site and materials, and that the use of these designs for long-range planning of waste storage requirements is appropriate. However, the Panel directs Shell to submit, for EUB approval, detailed geotechnical design for all external overburden disposal areas at least six months prior to field preparation in those areas.

The Panel accepts that on the basis of the available data, Shell has optimized the locations of the east and west overburden disposal areas, as well as the RMS, in order to minimize the sterilization of mineable oil sands. However, further drilling in these areas may indicate that the current overburden disposal areas and RMS footprints result in additional sterilization of mineable oil sands. The north overburden disposal area does not have sufficient drilling to warrant approval of the footprint at this time. Shell will be required to complete further drilling in the footprint of the north overburden disposal area. The Panel directs Shell to submit, for EUB approval, a resource assessment of the three waste disposal areas and RMS, two years prior to material placement.

The Panel believes that the resource information for each disposal area must be submitted at least two years prior to material placement, to ensure that there is sufficient time to complete any additional drilling that may be required. This requirement allows sufficient time for at least one full drilling season and an appropriate review period. The information may be submitted as part of the annual mine plan or under separate cover, but it is critical that the timing of the submission be appropriate.

The Panel notes that there is some level of uncertainty in the footprints of all the overburden disposal areas, which could impact the overall disposal capacity. It also notes that Shell intends to complete a significant amount of drilling prior to start-up, which could impact the overall material balance for the project. The Panel finds that while there is sufficient information for Shell to provide an adequate prefeasibility mine plan, an updated ten-year mine plan and material balance are required after the feasibility study has been completed. This will ensure that the project will progress in a way that is in the public interest. Therefore, the Panel directs Shell to submit, for EUB approval, a ten-year mine plan and material balance by the earlier of 2008 or six months prior to pit development.

6.5 Operating Criteria

6.5.1 Views of Shell

Shell stated that it evaluated the Jackpine Mine reserves using the operating criteria established in *ID 2001-7*. It determined final pit limits by using a TV:BIP of 12:1 and considering a number of physical constraints, including lease boundaries, Muskeg River, Jackpine Creek, and the PCA.

Shell stated that the expected bitumen recovery in the extraction process would meet or exceed the bitumen recovery requirements defined in *ID 2001-7* for the average ore grade of 10.7 mass per cent. Shell clarified that 10.7 mass per cent would be the average ore grade over the first 15 years of the mine life. However, Shell expected that situations might arise during operations that could result in these criteria not being met, particularly for lower grade ores. Shell stated that it was committed to filing a report with the EUB at the end of each year explaining overall recoveries achieved for that year and any deviations from *ID 2001-7*. Shell indicated that it would continue to engage in research and development with a view to improving current estimated recoveries.

Shell noted that there were a number of potential plant improvements that could increase bitumen recovery. Shell listed two other factors that would lead to higher ore recoveries: the absence of marine channel or tidal channel transition ore in the early years of mining, and Shell's ability to blend ore from shovels that would be operating at the site.

Shell also stated that it would participate in the review of *ID 2001-7*.

6.5.2 Views of the Panel

The Panel directs Shell to meet the resource recovery requirements specified in *ID 2001-7* for the reasons set out below.

The Panel notes that although Shell indicated that it would meet operating criteria requirements for the first 15 years of the project, Shell has not made the same commitment for the final years of the project. The Panel understands that Shell believes that the lower grade ores the mine may encounter in later years would negatively impact recovery. However, the Panel believes that Shell has sufficient time prior to start-up in 2010 and in the following 15 years of production to optimize its extraction process to increase recovery from the lower grade ores.

The operating criteria concept sets the requirements of resource conservation using a set of four criteria (TV:BIP, selectivity, cutoff grade, and extraction recovery) that are not individually subject to enforcement. It is the overall amount of bitumen recovered annually that Shell must achieve. If Shell's extraction plant recovery is low, it has the opportunity to offset any deficit in bitumen recovery by mining material over TV:BIP of 12, reducing cutoff grade, or altering selectivity. The Panel believes these criteria to be minimum industry standards and it expects operators to design plant facilities and mining operations in order to meet those standards.

The Panel notes that Shell said it would submit a report at the end of each year explaining extraction recovery attained throughout the year and any deviations from *ID 2001-7*. The Panel observes that the operating criteria performance measuring system is an after-the-fact system in that the quantity of bitumen that should have been recovered during a given year is estimated after the year is completed. If there is need for enforcement action, that would occur in the period following the year in which operating criteria are not met. As outlined in *ID 2001-7*, a report issued at the end of the year outlining deviations from the EUB directive would not preclude the EUB from subsequent enforcement action.

Notwithstanding the above, the Panel also understands that many challenges can occur during commissioning of an oil sands project. If Shell believes that it may be unable to meet *ID 2001-7* requirements during commissioning, the Panel expects Shell to submit a detailed plan specifying increased bitumen losses and providing technical and economic justification to the EUB for approval. The plan must be submitted at least three months prior to the processing of oil sands in the extraction plant.

ID 2001-7 requires that the EUB review the operating criteria in 2005, with a view to determining the reasonableness and appropriateness of the criteria. The Panel notes that the project will not be starting up until 2010 and thus would be able to incorporate any changes to the operating criteria that result from this review.

6.6 Mining Setbacks

6.6.1 Views of Shell

Shell noted that it used three criteria to determine the distance mining activity would be set back from the Muskeg River: areas of shrubby swamps, a 100 m undisturbed setback from the edge of the open water channel of the river, and a 400 m wildlife corridor measured from the Muskeg River Mine Miscellaneous Surface Lease (MSL) to the edge of the project disturbance area. Shell stated that it would construct a 100 m wide flood berm and a 65 m road and power line corridor between the setback line and the pit crest. Shell acknowledged that there was potential that mineable ore extended beneath the Muskeg River and indicated that 17.3 10^6 m^3 of bitumen in place, measured from the edge of the MSL to the toe of the proposed pit face, would be left below the Muskeg River, the Muskeg River offset, and associated infrastructure.

Shell stated that a regional wildlife movement corridor study was within the mandate of CEMA. It further stated that it would participate in the appropriate CEMA subgroup and would help fund and design the study.

Shell indicated that mining activity would be set back 100 m from Jackpine Creek. The northernmost section of Jackpine Creek, near the confluence with the Muskeg River, would also require a flood berm.

6.6.2 Views of the Panel

The Panel recognizes that environmental setbacks provide needed wildlife corridors and habitat protection, but notes that mineable oil sands would be sterilized and recovery of the resource would be negatively impacted. The Panel is prepared to accept the proposed setbacks and the associated loss of oil sands resource in order to protect the environment.

The Panel recognizes that a CEMA subgroup is implementing a regional wildlife movement corridor study and that the group's findings may impact the proposed width of the 400 m wildlife corridor. This issue is further addressed in Section 16.1. The Panel also notes that the MRWI subgroup is working towards management objectives for the watershed. The Panel notes that these objectives could also potentially impact the proposed setback from the Muskeg River and are required by Shell and the EUB to make resource management decisions. The Panel observes that the results of further work by CEMA may indicate a need for a larger setback from the Muskeg River. In that case, the amount of resource at risk of being sterilized could increase substantially. The Panel expects that Shell will evaluate the impact of implementing approved results from the CEMA subgroups dealing with the wildlife corridor and MRWI. If there is potential to sterilize additional resources, Shell is required to submit a report for EUB approval containing a comprehensive description of the reserves within the setback, geotechnical conditions, alternative mining scenarios, environmental impacts of each scenario, and associated costs, in accordance with Section 3.1 of *ID 2001-7*.

The Panel supports the disturbance setbacks, provided that the desired protection is achieved, and believes that these setbacks should be maintained, once established. The Panel notes that Shell has proposed multiple criteria to determine the setback from the Muskeg River, including a 100 m setback from the edge of the open water channel. The Panel expects Shell to maintain all the proposed setbacks and will direct that the project area exclude the 100 m setback from the Jackpine Creek and the Muskeg River, as shown in Figure 1. The Panel has adjusted the project area to accommodate the access road and utility corridor, since each would cross the 100 m setback. The Panel believes that the 100 m setback would allow Shell some flexibility within the project area if results from the CEMA committees indicate that the 400 m wildlife corridor could be decreased or if avoiding shrubby swamps is not necessary.

6.7 External Tailings Disposal Area Location and Design

6.7.1 Views of Shell

Shell indicated that it investigated six different external tailings disposal area locations to contain the estimated 571 10^6 m^3 of tailings production. Shell noted that the mining pit, the Khahago surge facility, the Khahago diversion spillway and the south lease boundary, the plant site, and the east overburden disposal area all surround the tailings disposal area. Shell investigated increasing the capacity of the tailings external impoundment by raising the tailings disposal area dikes without changing the footprint.

Shell identified a marginal mining area, denoted as area DH-141, which encroached on the northwest corner of the tailings disposal area, but stated that this area was not economical to mine. Shell stated that while it did not provide the results of combining area DH-141 and SH02-537, work that was completed resulted in a higher combined TV:BIP value than that of either of these pit extensions on their own. SH02-537 was a marginal zone that encroached on the plant site. Shell said that it would complete drilling along the pit limit near the plant site and tailings disposal area prior to finalizing the footprint of either of the sites (Figure 1).

Shell stated that the external tailings disposal area would need to accommodate the tailings production before in-pit storage was possible. The tailings disposal area was designed as a segmented facility divided into a zone for thickened tailings and another zone for a Tailings Solvent Recovery Unit (TSRU) and conventional tailings. Shell indicated that it had not completed any site-specific geotechnical evaluation of the tailings disposal area foundation.

Shell stated that the outside slope of the tailings dike in the southeast corner would be shallower to accommodate the presence of Clearwater clays. In addition to the shallower slope, there was a possibility that a 200 m wide toe berm would be required to stabilize the slope. Shell also proposed to locate the Khahago surge facility in this area. Shell stated that the surge facility would be excavated to a depth of 13 m and could be designed to maintain geotechnical stability of the tailings disposal area.

Shell indicated that it would do further site-specific geotechnical investigation. Shell stated that it would provide the EUB and AENV's Dam Safety Branch with the final tailings disposal area design one year prior to impoundment. Shell also stated that the Khahago surge facility would be constructed earlier than the tailings disposal area and that Shell would provide the design of the facility prior its construction.

In an agreement with MCFN, Shell committed to incorporating additional on-site water storage in the design of the project in the external tailings disposal area, recycle water pond, raw water pond, and Khahago surge facility. Shell indicated that the additional on-site water storage would minimize water withdrawal from the Athabasca River during low-flow periods for up to 30 days. Shell indicated that the 30-day storage commitment would not impact the tailings management plan. Shell did not see any reason to look for off-lease storage solutions.

6.7.2 Views of the Panel

The EUB's responsibility when considering applications for tailings disposal areas is to address their purpose, location, and preliminary engineering design. *Informational Letter (IL) 94-19: The Dam Safety Accord*, specifies that the EUB's role with respect to new external tailings disposal areas is to ensure that structures are located such that resource sterilization is minimized, the facilities are needed and sized to adequately service the proposed project, the site is appropriate, considering logistics as well as environmental acceptability, and the proposed design meets the requirements for worker and public safety and for the integrity of the project.

The Panel believes that the tailings disposal area is sufficient for the prefeasibility planning stage. However, modifications to the tailings management plan or changes to the project layout may negatively impact the tailings disposal area footprint and the proposed capacity. Further, due to the proximity of the plant site, Khahago surge facility and diversion, and the mining pit, there is no additional land available for expansion on Lease 13. There may be an opportunity for Shell to expand south of its lease, but this would require some form of regional cooperation between leaseholders. While Shell indicated that it has the ability to raise the tailings disposal area dikes, the Panel believes that this would increase the capacity by only a small amount.

The Panel believes that the Khahago surge facility may impact tailings disposal area stability. Further geotechnical investigation and a more detailed design may mitigate these concerns. The Panel notes that the Khahago surge facility would be constructed prior to the tailings disposal area and believes that sufficient design work must be completed in parallel with the external tailings disposal area design to ensure that the surge facility will not compromise the tailings disposal area design. The Panel believes that there may be opportunity to change the location of the surge facility in cooperation with neighbouring leaseholders.

Having regard for the above, the Panel will include a condition in the EUB approval for Shell to satisfy the EUB, two years prior to construction of either the Khahago surge facility or the tailings disposal area, that the design of the tailings disposal area, including the surge facility, provides for adequate capacity, stability, and minimization of resource sterilization and environmental impact.

The Panel notes that Shell might use the tailings disposal area to store water for use during low-flow conditions in the Athabasca River. The Panel is concerned that rapid water withdrawal from the tailings disposal area could cause instability in the upstream tailings dike. The Panel expects AENV's Dam Safety Branch to require Shell to address upstream tailings dike stability in the detailed design.

The Panel concludes that the tailings disposal area is unlikely to result in significant adverse environmental effects, provided that the necessary design work is undertaken, submitted, and implemented.

6.8 Project Timing

6.8.1 Views of Shell

Shell stated that its overall development schedule was focused on achieving production of oil beginning in 2010. Site preparation would start in early 2005. In 2001/2002, Shell completed the prefeasibility study and conceptual engineering design of the project. Shell stated that an approval of the project was needed by the end of 2003 to allow for an initial investment decision and start of the feasibility study.

Shell stated that it would be opposed to a sunset clause in its approval. Shell indicated that a number of issues still had to be addressed after regulatory approval before the project would proceed, such as satisfying commitments to stakeholders and managing environmental issues. Shell stated that it had to be confident that it could build this project on time and on budget.

6.8.2 Views of the Panel

The Panel is satisfied that Shell has provided sufficient and adequately detailed information for the Panel to approve the project at this time. The Panel notes that Shell has completed a prefeasibility study and that there may be design changes as new information becomes available. The Panel expects that in the next ten years there will be additional technological development, particularly on tailings management, that may be applied. It also expects environmental management objectives and systems to be developed through CEMA and approved by government, and they may affect the project design. It further notes that Shell has a number of matters to complete prior to the project moving forward. Therefore, to the extent there are changes to the project design, the Panel directs Shell to provide an annual report to the EUB on the status of the project and its development commencing on February 28, 2005, or such other date and frequency the EUB may stipulate.

7 BITUMEN PRODUCTION

7.1 Views of Shell

Shell stated that the proposed bitumen extraction process would meet the operating criteria requirements for average-grade oil sands of 10.7 mass per cent bitumen and higher. Shell committed that it would continue research and development to improve the current estimated recoveries on low-grade ores and to provide the EUB with an update on its progress. It also noted that it would continue to investigate methods to recover bitumen from rejected ore.

Shell indicated that it was doing bench-scale flotation tests to determine the separation characteristics of asphaltenes and solvent in TSRU tailings and the feasibility of recovering the hot water from this stream. It indicated that the solvent was in the asphaltene portion and not the water phase. Shell stated that tests to thicken TSRU tails looked promising, and therefore the water could possibly be recycled back into the process.

Shell noted that the paraffinic froth treatment process would reject asphaltenes with the fine solids in tailings to produce a marketable bitumen product. The estimated asphaltene rejection would vary from 6 to 10 mass per cent. Shell stated that it would accept a condition in its approval limiting asphaltene rejection to 10 mass per cent based on bitumen production.

Shell stated that it had designed the tailings solvent recovery system with three equal-sized trains, of which two could handle the full production, thus providing 50 per cent redundancy. Each TSRU would consist of two stages of solvent recovery to control the losses in tailings prior to discharge to a tailings disposal area. Shell committed to limit its annual average site-wide solvent losses to 4 volumes per 1000 volumes of bitumen production. Shell also committed that it would not discharge untreated froth treatment tailings to the tailings disposal area.

7.2 Views of Alberta

AENV stated that it expected the plant to be designed and operated in a manner that minimized the frequency of odours incidents resulting from emissions of volatile organic compounds (VOCs) and other odorous compounds. AENV also stated that it might include conditions in the EPEA approval that would require Shell to provide 100 per cent TSRU redundancy or to reduce throughput when necessary to ensure that untreated tailings were not sent to the tailings disposal area and consequently that VOC emissions were minimized under all operating conditions.

7.3 Views of the Panel

The Panel encourages oil sands developers to use extraction technology that will maximize resource recovery, reduce energy and water consumption, and minimize fluid fine tailings production. The Panel believes that Shell is attempting to meet these goals by its choice of extraction process and the use of thickeners. The Panel understands that the proposed extraction process is presently being used at the Muskeg River Mine and that Shell will apply knowledge gained to the Jackpine Mine design and operation.

The Panel is prepared to accept Shell's proposed extraction process and expects it to achieve a bitumen recovery that allows it to meet EUB operating criteria. The Panel notes Shell's concern with recoveries from low-grade ores and Shell's commitment to research and development to improve the current estimated recoveries. The Panel directs Shell to provide a report on progress in improving the bitumen extraction recovery in every second annual report to the EUB, starting in 2008, or such other date and frequency the EUB may stipulate.

The Panel understands that Shell is continuing to evaluate TSRU thickeners and that Shell has seen promise in this technology. The Panel directs Shell to continue to evaluate TSRU thickeners technology and report results to the EUB in the 2006 annual report. The report must identify any opportunities to include TSRU thickeners in the project design and construction. The Panel also notes that Shell is testing separation characteristics of asphaltenes contained in TSRU tailings. Therefore, it directs Shell to report on its progress in dealing with separation characteristics of asphaltenes in the TSRU tailings in its annual report to the EUB commencing in 2005, or such other date and frequency the EUB may stipulate.

The Panel notes that Shell would be using a paraffinic solvent extraction process, which would result in asphaltene rejection and disposal with the TSRU tailings. The Panel accepts that higher quality bitumen provides a more marketable product than non-deasphalted bitumen, but is concerned about the rejection of asphaltenes, a potentially usable resource. The Panel directs that on or before February 28 of each year commencing in 2011, Shell shall provide to the EUB a summary of the previous year's operation stating the amount of asphaltene rejected. The Panel also directs that the amount of asphaltenes rejection shall be limited to 10 mass per cent based on bitumen production.

The Panel accepts Shell's commitment to limit annual average solvent losses to 4 volumes of solvent per 1000 volumes of bitumen production to minimize the potential VOC emissions and off-site odour incidents. This calculation shall be based on site-wide losses and shall include losses through vents and TSRU losses during all operating conditions. The Panel also accepts Shell's commitment that it would not discharge untreated froth treatment tailings to the tailings disposal area during normal operations. The Panel notes that these criteria are presently being applied to the Muskeg River Mine. Therefore, the Panel directs that on an annual average basis, Shell must limit site-wide solvent losses to not more than 4 volumes per 1000 volumes of bitumen production under all operating conditions. The Panel also directs Shell not to discharge untreated froth treatment tailings to the tailings disposal area.

The Panel concludes that the proposed extraction process and solvent losses are unlikely to result in significant adverse environmental effects, provided that the proposed mitigation measures and panel recommendations are implemented.

8 TAILINGS MANAGEMENT

8.1 Views of Shell

Shell stated that its objectives for the project tailings management plan were to manage the extraction plant tailings streams economically and in a manner that would minimize the out-of-mine impact. Shell wanted a stable, long-term landscape, consistent with effective reclamation and mine closure planning. The plan would place tailings into the mined-out pits as soon as possible, minimize the size of the external tailings disposal area, and advance reclamation of the mine pits.

Shell stated that the tailings management plan for the project would use an external tailings disposal area for the initial tailings disposal. It stated that it would convert to consolidated tailings (CT), consisting of a mixture of coarse tailings, thickened tailings, and gypsum, in-pit after about six years of operation. It noted that there were no other proven commercial options available to better meet its tailings management objectives.

The project would produce three tailings streams, a coarse slurry stream from the cyclone underflow of the primary separation vessels, a thickened tailings (TT) stream from the thickeners, and a segregating TFT stream from the TSRU into the external tailings disposal area. After about six years, CT would be deposited in the mined-out pits.

Shell estimated that CT would be produced as a nonsegregating mixture 81 per cent of the time. During non-CT operation, segregated sand and TFT would be produced.

Shell stated that all mined-out pits containing CT and the external tailings area would be reclaimed as dry landscapes at mine closure. The TT cell and two in-pit cells would remain as EPLs. Shell noted that the area of these EPLs represented less than 15 per cent of the total tailings disposal area. Shell stated that it would expedite progressive reclamation in the disturbed areas by creating CT with a sand-to-fines ratio of 5:1, allowing reclamation to be completed between three and five years after the end of tailings placement in the CT cells. Shell stated that excess mature fine tails (MFT) would be transferred to the EPLs and capped with water. It noted that the EPLs would eventually be self-sustaining, biologically productive water bodies that provided aquatic habitat. Shell stated that it had tested CT performance over a range of sand-to-fines ratios at the Muskeg River Mine. The tests indicated that it might be possible to allow lower CT sand-to-fines ratios, thereby reducing or eliminating the in-pit water-capped TT cell.

Shell stated that it was pursing other tailings management options through specific research programs, jointly through the Canadian Oil Sands Network for Research and Development (CONRAD), and through performance evaluations from Muskeg River Mine operations. It was committed to continue participating in regional and international research programs related to tailings properties and to ongoing research in the areas of paste pipeline flow studies, stacking, fine tailings mechanical thickening, TSRU tailings heat recovery, and reduction of moisture content of coarse tailings. Shell believed that there were no viable commercial tailings strategies other than those presented in its application.

8.2 Views of the Panel

The Panel believes that appropriate tailings management objectives for oil sands mines should be

- maximizing immediate process water recycle to increase energy efficiency and reduce fresh water import;
- minimizing stored process-affected water volumes on site;
- eliminating or reducing containment of fluid fine tailings in an external tailings disposal area during operations;
- minimizing and eventually eliminating long-term storage of fluid fine tailings in the reclamation landscape; and
- creating a trafficable landscape at the earliest opportunity to facilitate progressive reclamation.

The Panel accepts Shell's proposed tailings management scheme. The Panel believes that the proposed CT scheme takes positive steps towards achieving many of the above objectives.

The Panel recognizes that Shell would consume most of the coarse tailings solids and 60 per cent of the MFT in CT, with the remaining 40 per cent of the MFT transferred to an EPL. This scheme will not meet the objective of eliminating long-term storage of fluid fine tailings in the reclaimed landscape. The Panel notes that Shell will not commence production of CT until six years after start-up. The Panel believes that Shell should investigate opportunities to start CT production earlier so as to consume more of the MFT. The Panel directs Shell to submit a report to the EUB prior to final design or on June 30, 2006, whichever is earlier, on the feasibility of producing CT on commencement of operation in order to reduce the accumulation of TT, TFT, and MFT.

The Panel believes that tailings management is one of the main challenges for the oil sands mining industry. This challenge persists, despite considerable efforts over more than 40 years to develop alternative bitumen extraction and tailings management schemes that do not produce fluid fine tailings. Current tailings management results in tailings having to be impounded indefinitely and prevents reclamation of tailings areas. The challenge is more problematic since there is currently no demonstrated means to reclaim fluid fine tailings. The Panel notes that a reclamation scheme consisting of water capping of fluid fine tailings in an in-pit pond was applied for and endorsed by the EUB subject to a successful demonstration in EUB *Decision 94-5: Syncrude Continuous Improvement and Development Project, Mildred Lake Oil Sands Plant*. This demonstration is a major undertaking and considerable work has already been completed, with more expected to occur over the next 20 years. In the absence of a demonstrated successful case of reclamation of fine tailings by water capping, the EUB has previously directed oil sands mining developers to continue to work on alternative technologies for bitumen extraction or tailings management to ensure that acceptable reclamation of all tailings deposits will be achieved.

Therefore, the Panel expects Shell to continue to work to develop solid tailings technology and to evaluate the feasibility of implementing such technology at the project. The Panel directs Shell to describe its progress on developing solid tailings technology in every second annual report to the EUB commencing on February 28, 2005, or such other date and frequency the EUB may stipulate.

The Panel believes that it is imperative to produce high-quality CT consistently to ensure that the objective of a trafficable landscape that allows rapid progressive reclamation of tailings areas can be met. The Panel notes Shell's overall on-stream factor of 81 per cent and believes that a higher service factor is achievable and necessary to meet this objective. The Panel recognizes that considerable attention to equipment design and operation would be required to achieve a higher service factor and to ensure that the mixture consolidates and remains in a nonsegregated state. Therefore, the Panel directs Shell to submit to the EUB a report summarizing the engineering design and operating plans for the CT system two years prior to planned start-up or on such other date as the EUB may stipulate. The Panel also directs Shell to submit to the EUB on or before February 28 of every year commencing in 2011, or such other date or frequency as the EUB may stipulate, a report summarizing the performance of the tailings management system during the preceding year, including Shell's reasons for any deviations from design.

The Panel believes that Shell's proposed tailings management scheme is reasonable, based on current technology, but that there is need for further development efforts and for the regulators to ensure that Shell and other oil sands developers effectively manage tailings.

The Panel has considered a number of regulatory options to ensure that tailings are managed satisfactorily. In EUB *Decision 2002-089: TrueNorth Energy Corporation, Application to Construct and Operate an Oil Sands Mine and Cogeneration Plant in the Fort McMurray Area*, the EUB limited the maximum amount of project disturbance, which had the effect of imposing tailings management performance criteria to some degree. The Panel believes that this work could start by considering the factors that relate to fluid fine tailings consolidation, such as percentage of solids utilization, quality of tailings produced, and tailings system service factor. The Panel does not believe that it has adequate information in these proceedings to establish performance criteria for tailings management. Additionally, the Panel is concerned about potential inconsistencies when criteria are established on a project-by-project basis. The Panel believes that uniform criteria would allow the EUB to regulate more effectively in this area. Ideally, the criteria would be performance based, with the discretion left to operators as to how to meet the requirements. The Panel is not in a position at this time to set such criteria but believes that work should commence without delay to develop these criteria.

The Panel notes that the approval of discard management plans is the regulatory responsibility of the EUB and, therefore, it is appropriate for EUB staff to lead the initiative and consult with mineable oil sands developers. Due to the close linkages between tailings performance and reclamation issues, the Panel believes that this initiative would benefit from the participation of AENV and ASRD, since these departments have reclamation approval responsibilities under EPEA and the Public Lands Act (PLA). Therefore, the Panel will direct EUB staff to work with the mineable oil sands industry, AENV, and ASRD to develop performance criteria for tailings management. The Panel expects this work to result in a recommendation to the Board on the appropriate tailings management performance criteria by June 30, 2005.

The Panel notes that work continues on water capping of fine tailings. The Panel believes that ongoing tailings research will identify alternative means to reclaim fluid fine tailings, perhaps at a higher cost than water capping, if water capping fluid fine tailings proves to be unacceptable.

The Panel believes that close attention to design and operations supported by continued aggressive research by Shell and continued monitoring by EUB and AENV will ensure that Shell's proposed tailings management is unlikely to have significant adverse environmental effects.

9 WATER MANAGEMENT

9.1 Views of Shell

Shell stated that the project would minimize freshwater use by maximizing water recycle in the process. This would be accomplished through the use of tailings thickeners and the use of a noncaustic extraction process that enhanced settling characteristics of tailings and allowed faster release of water for recycle. Shell also stated that it would use surface water and groundwater from the basal aquifer and the PCA to further minimize water withdrawal requirements from the Athabasca River. Shell noted that ambient water quality of the PCA exceeded Canadian drinking water guidelines.

Shell planned to use PCA, basal aquifer, and Athabasca River water for bitumen processing. The addition of Athabasca River water would reduce total dissolved solids (TDS) and maintain overall water quality. Shell could not use the PCA for primary source water for extraction because its water chemistry would impact bitumen recovery.

Shell stated that it would require 15 10^6 m^3 of water storage capacity for pre-start-up in the project external pond disposal area to

- mitigate the peak rate of withdrawal from the Athabasca River during start-up,
- mitigate the quality of supplemental water sources, and
- ensure adequate water for start-up and operations during the early months of peak water demand.

Shell stated that additional water was required for about the first six years of mine start-up and operations while tailings were placed out-of-pit. Shell stated that it would require 4.66 m^3 of fresh water per m^3 of bitumen production, or about 60 10^6 m^3 per year. During steady-state operations when depositing CT in-pit, it would strive for a significant reduction in water use. Shell noted that it would require 2.76 m^3 of fresh water per m^3 of bitumen production, or about 35 10^6 m^3 per year, during steady-state operations. An additional 373 10^6 m^3 of water would be needed at the end of the project life to fill in-pit lakes.

Shell stated that it was requesting a maximum water licence allocation from the Athabasca River of 63.5 10^6 m^3 per year. It was also requesting a maximum instantaneous withdrawal rate of 4.17 m^3/s from the existing Muskeg River Mine water intake structure. First withdrawals from the Athabasca River would not occur until 2010. Shell noted that no increase in the current capacity of the water intake was planned for the project.

Shell recognized that one of the main issues of concern to stakeholders in the region was the future cumulative withdrawal of water from the lower Athabasca River, particularly during the low-flow period from January to March. Shell understood that stakeholders were concerned with the issuance of new water licences by AENV in the absence of a formal IFN management system for the Athabasca River. Shell noted that the maximum water withdrawal from the Athabasca River during extreme low-flow conditions would decrease river levels by less than 1 centimetre and overall flow would decrease by less than 2 per cent. Shell stated that the EIA classified the effects to river flow and water level as nonmeasurable. It committed to verifying the predictions of its EIA and designing a follow-up program to monitor for and adaptively manage the effects of its project.

Shell believed that an IFN management system would be finalized by CEMA in 2005, five years before the operation of the project and Shell's initial water withdrawal. In response to stakeholder interests and in anticipation of potential restriction during low-flow periods, Shell indicated that it was taking a precautionary approach. This included development of additional on-site water storage capacity in the tailings disposal area, recycle water pond, raw water pond, and Khahago surge facility. The additional water storage would allow Shell to minimize its water withdrawal for up to 30 days during low-flow periods.

Shell stated that after six years it could reduce water withdrawal from the Athabasca River for 30 days to a minimum of 0.45 m^3/s required to operate at steady state. Shell indicated that removal of this small volume of Athabasca River water during low-flow periods was still necessary to protect Shell's water supply pipeline from freezing and to feed the boilers.

Shell stated that it supported a phased water licence for the project, provided that similar phased licences were issued to other oil sands projects in the area. Shell said that it had not changed its water licence application to reflect a phased or tiered approach but would be supportive if AENV granted such a water licence. If granted, a licence could include volumes for steady-state operations and higher volumes for short-term water allocation during the first six years of project start-up. However, Shell believed that some flexibility was needed for additional water volumes during steady-state operations and stated that it would apply to AENV for an additional short-term allocation. Shell noted that water licences were typically issued for ten-year terms.

9.2 Views of OSEC

OSEC stated that no new water allocations should be granted until an interim IFN limit was established or the CEMA IFN subgroup determined an IFN management system for the Athabasca River. Either should be in place before Shell needed to withdraw water for the project. OSEC and Shell agreed that AENV Water Act licences should reflect long-term water requirements of the project, allowing Shell to use short-term licences for its start-up period water needs.

OSEC noted that the application before the Panel did not reflect OSEC's agreement with Shell for a minimum water allocation. OSEC understood that it was AENV's decision on how best to allocate water. OSEC believed that AENV could issue a ten-year licence for the base requirements and then issue a supplementary licence for the increased needs during the start-up period.

9.3 Views of MCFN

MCFN stated that it was satisfied with Shell's commitment to stop withdrawal from the Athabasca River if needed and with Shell's plans to have a 30-day water storage as a solution to MCFN's concern about withdrawals during low-flow conditions in the Athabasca River. MCFN also noted that the project was scheduled far enough into the future to set an IFN prior to the project moving forward.

MCFN recommended that the Director under the Water Act ensure that

- any future licences for withdrawal from the Athabasca River for oil sands development include a provision for a cooperative management strategy to restrict water withdrawals during low-flow periods and to accommodate a regulated IFN number;
- the transfer or sale of water withdrawal allocations among oil sands developers be prohibited;
- no exemptions to withdrawal restrictions during low-flow periods be granted;
- licences be tied to a proponent's actual needs and be subject to change depending upon IFN of the Athabasca River; and
- consideration be given to attaching a cost of water to industrial users that reflects the value of the resource.

MCFN made further recommendations to Alberta's Minister of Environment to

- develop a lower Athabasca River Basin water management plan, with AENV taking the lead in the development of this plan and MCFN and other stakeholders being afforded opportunities for participation and input;
- establish a registry to receive and publish water complaints; and
- establish a registry to track the amount of water allocated and used under various water licences in the region.

MCFN further recommended that AENV and Canada immediately set a conservative interim IFN for the Athabasca River and that AENV set 2005 as the firm deadline to establish a consensus-based or regulated IFN without allowing further extensions to CEMA's work schedule.

9.4 Views of WBFN

WBFN expressed concerns about environmental effects on the Peace/Athabasca Delta, effects on wildlife, and the need to determine factors contributing to low water levels in the delta, such as the Bennett Dam and oil sands plants. WBFN stated that until there was resolution of such issues, no more water withdrawal approvals from the Athabasca River should be issued. WBFN expressed a need for an assessment to determine the reasons for the deteriorating condition of the delta before more water licences were issued.

9.5 Views of Alberta

AENV stated that it intended to include conditions in the Water Act licence issued allowing for implementation of management options based on IFN in the Athabasca River. AENV would carefully evaluate the exact amount of water allocation after considering the evidence from the hearing and the Panel's report. AENV acknowledged that all of the existing oil sands Water Act licences had terms and conditions that would allow for the cessation or reduction of water withdrawal should AENV implement a management system for IFN.

AENV said that it accepted on-site water storage as one of the strategies to reduce water withdrawals during low-flow conditions. AENV stated that it was Shell's responsibility to deal with any future limitations on water withdrawals during low-flow periods or any other restrictions on water users.

Alberta stated that the overall annual volume of water available from the Athabasca River was more than sufficient to support Shell's requested allocation. AENV acknowledged that during winter low-flow periods there was potential for cumulative impacts to the Athabasca River. To minimize potential impacts, the timing of low-flow water withdrawals could be managed and withdrawals could be scaled back or managed within IFN objectives without reducing allocations. CEMA was engaged in developing an IFN management system scheduled for completion by the end of 2005. AENV committed to take necessary action should CEMA not be able to advance its IFN recommendation by the end of 2005.

AENV stated that there was provision within the Water Act for water management planning similar to that suggested for the Athabasca River and that this planning function was not exclusive to the Alberta government. AENV referred to the Alberta draft water strategy whereby local or regional groups could participate in basin planning.

9.6 Views of the Panel

The Panel has reviewed Shell's water balance data and water requirements for the project. The Panel understands that Shell's tailings management scheme includes immediate water recycle that will reduce the total make-up water requirements. The Panel notes that 2.76 units of fresh water per unit of bitumen production are required to operate Shell's process on a long-term sustainable basis during steady-state full production. The Panel finds that Shell's water requirement during the initial start-up phase is consistent with the requested allocation from the Athabasca River of 63.5 10^6 m^3 per year. The Panel accepts that water is needed for the project and the most suitable source of water is the Athabasca River.

The Panel therefore recommends that in AENV's review of Shell's Water Act application, it consider water allocation based on needs of the different project phases. The Panel notes that both Shell and interveners were supportive of a phased water licence.

The Panel supports Shell's plan to develop 30-day water storage on site provided that the design can be incorporated into the mine plan without adverse impacts to resource recovery, safety, or the environment.

With respect to IFN, the Panel agrees that there is a need for CEMA and AENV to implement a management system prior to water withdrawals by Shell for the project. The Panel expects CEMA to make its recommendation for an IFN management system to AENV by the end of 2005. The Panel recommends that AENV establish IFN for the Athabasca River in collaboration with DFO in the event that CEMA fails to meet its timelines. The Panel supports AENV amending existing Water Act licences for IFN management, if that becomes necessary.

The Panel does not believe that setting of interim IFN is necessary. In addition, the Panel believes that work to establish interim IFN might result in resources being diverted from the process of determining permanent IFN.

The Panel recognizes that interveners recommended several actions concerning administration of Water Act licences be taken by AENV. The Panel acknowledges that the release of AENV's *Water for Life Strategy* may influence a number of water resource management priorities, with resulting changes to the administration of Water Act licences. The Panel has confidence that in the exercise of its regulatory authority, AENV will address the needs of regional stakeholders, existing licence holders, and applicants seeking new water allocations.

Regarding the recommendation of MCFN to establish a river basin management plan for the lower Athabasca River, the Panel notes that AENV stated that no such activity was presently within the work plan of CEMA. AENV referred to provisions within the Water Act and the *Water for Life Strategy* that would enable stakeholders to initiate and participate in water management plans. The Panel strongly encourages AENV to work cooperatively with regional stakeholders and water licence holders to evaluate a process and establish a water management plan for the lower Athabasca River.

MCFN has recommended public registries to address water quality complaints and the tracking of licensed versus actual water use by regional water licence holders. In the first instance, AENV stated that it does manage a 24-hour telephone hotline for environmental complaints and emergencies throughout the province. The Regional Aquatics Monitoring Program (RAMP) also provides information to local communities about contacts and organizations able to assist citizens with complaints about regional water quality. Additionally, water licence holders report their actual water use to AENV as a regulatory requirement. That information is publicly available. The Panel recommends that AENV review the communications programs in place to ensure that regional water quality and water use information is accessible and understandable to interested parties.

The Panel concludes that significant adverse environmental effects from the proposed water allocation are unlikely to occur, provided that the proposed mitigation measures and the recommendations of the Panel are implemented.

10 SURFACE WATER QUALITY

10.1 Views of Shell

Shell completed an environmental assessment of project activities predicted to alter water quality within the project area, including the release of muskeg drainage and depressurization waters, EPL releases, altered groundwater regimes, disruption of stream channels, tailings seepage, runoff from CT and reclaimed surfaces, and acidifying emissions. Shell predicted that with appropriate mitigation measures, these project activities would have negligible environmental effects on the water quality of the Muskeg River watershed and Shell's EPLs. Shell stated that process-affected surface waters would be contained within a closed water management system and not released off site.

In all cases, whether from project activities or from regional or cumulative effects, Shell concluded that effects on water quality in the Athabasca River or its tributaries would be negligible. Shell also stated that effects of water quality on fish health and fish tainting would similarly be negligible.

Shell observed some instances of degraded water quality in naturally occurring waters of the Muskeg River drainage basin. Shell's EIA also indicated that Athabasca River water exceeded some water quality guidelines and influence EPL water quality. Using the Hydrologic Simulation Program in Fortran (HSPF) model, Shell predicted water quality conditions for the Muskeg River drainage basin from four time intervals during the life of the project. Shell fitted the predicted water quality parameters to frequency distributions of historical water quality data. Shell then compared the data sets to established regulatory criteria and the compliance levels assessed against 99.91 percentile concentrations, as recommended by the U.S. Environmental Protection Agency. Shell gave consideration to ambient concentrations and the observed range of natural variability.

Shell assessed sediments containing chromium, naphthenic acids, and manganese for Jackpine and Muskeg Creeks when screening for exceedances and possible effects on fish health. Shell predicted that the effects of sediment quality on fish health would be negligible. Shell identified surrogate values for naphthenic acid toxicity of sediments, as actual data were not available.

Shell addressed uncertainties in its water quality predictions by providing worst-case scenarios and other measures that overpredicted effects of the project (e.g., no attenuation of in-stream contaminants, simultaneous release of reclamation waters from other projects). Shell adopted regional initiatives such as CEMA and RAMP as a means to reduce uncertainty, manage cumulative environmental effects, and conduct research related to aquatic ecosystems. Shell recognized that mitigation measures were necessary to limit the release of contaminants to receiving waters and to maintain acceptable ratios of process-affected waters to natural runoff flows. Shell's environmental assessment assumed that for mitigation measures to be effective, other oil sands operators would adopt equivalent mitigation measures for the protection of flows and water quality of water bodies.

Shell predicted that air emissions from the project were likely to have moderate to high residual environmental effects upon acidic deposition in the region. As a result, Shell assessed potential effects of those acidic emissions upon ecological receptors, such as regional water bodies and aquatic resources, using lake-specific critical loads (CL) for comparison with potential acid input (PAI) predicted by dispersion modelling. Shell observed that for several regional lakes, acid deposition loadings exceeded CL values under baseline conditions. However, the project emissions contributed only incremental changes to CL exceedances and those incremental changes did not contribute to further exceedances in any other lake. Shell concluded that acidification effects on aquatic water bodies, including spring acid pulses, were negligible. Shell noted that in the future it would address acidification effects by adopting the CEMA acidification management plan. Shell also noted that it would manage potential changes in acidification of water by means of the annual monitoring now conducted by RAMP.

10.2 Views of OSEC

OSEC confirmed in its agreement with Shell that it was satisfied that Shell would comply with the necessary water quality criteria for EPLs. OSEC believed that appropriate water quality criteria would be recommended by CEMA and implemented by Alberta regulators.

10.3 Views of MCFN

MCFN requested that the Panel make recommendations or approval conditions for Shell to address specific environmental requirements of its community. Some of these included requirements for direct involvement of MCFN in the design and review of water quality, EPLs, and wetlands monitoring programs. MCFN requested that the Panel recommend or require Shell to integrate the results of monitoring programs so that Shell's EIA predictions could be validated.

10.4 Views of WBFN

The Wood Buffalo First Nation (WBFN) identified several concerns related to water quality. In relation to the increased water withdrawals of oil sands operations, WBFN said that its members had observed saline and sulphur springs flowing into the Athabasca River. It believed these springs could negatively affect Athabasca River quality during low-flow conditions. WBFN noted historical accounts from its elders of declining water flows and quality in the Peace/Athabasca Delta. The WBFN advised the Panel that more regional water quality data was needed prior to new water licences being granted.

10.5 Views of ACFN

ACFN indicated that its agreement with Shell resolved its issues related to water quality. Shell agreed to ACFN's request for the collection of baseline water quality and quantity data and for yearly monitoring of Kearl Lake and McLelland Lake, which are close to the project area. ACFN asked Shell for commitments that its project would not negatively affect Kearl Lake or McLelland Lake.

ACFN asked to participate in Shell's monitoring programs for surface and groundwaters in both the design of these programs and the development of threshold values and Shell's management action. Shell was asked to support the management system and objectives for maintaining the Muskeg River basin integrity that might be recommended by CEMA and adopted by Alberta regulators. Regarding EPL water quality, ACFN sought commitments from Shell similar to those included in Shell's agreement with OSEC.

10.6 Views of SCC

The Sierra Club of Canada (SCC) was concerned about potential changes to the Athabasca River system as a result of climate change. SCC was concerned that those changes would be exacerbated by increased water withdrawals by oil sands operations and result in increased concentrations of heavy metals and naturally occurring toxics. Other potential changes to water quality might occur from tailings disposal area impoundment failure or flood conditions.

10.7 Views of Canada

EC provided advice to the Panel concerning the water quality of tailings release and EPL waters. EC was concerned that EPLs contained tailings materials that would discharge to fish-bearing waters. EC stated that there was uncertainty regarding the removal of contaminants via EPLs and wetlands and uncertainty about the mobilization of dissolved or adsorbed substances into the food chain. EC recommended that Shell complete a long-term surface water and sediment quality monitoring plan that

- characterizes ongoing conditions in the development area,
- enables comparative analysis between before/after and control/impact conditions,
- tests water and sediment quality predictions, and
- evaluates effectiveness of mitigation measures.

EC advised that predictions of water quality baseline and future conditions used in Shell's environmental assessment sometimes depended on limited historical data. EC stated that most predictions of water quality lacked confidence limits, as Shell had not calculated statistical uncertainties. EC recommended that Shell conduct further baseline and operational water and sediment quality sampling. This would improve scientific knowledge of predisturbance conditions and improve validation of Shell's predicted effects on water and sediment quality during the course of the project. EC recognized the potential for additive or synergistic effects on the Athabasca River based on effluents and water withdrawals. EC recommended to the Panel that more information on potential effects on the Athabasca River be acquired through regional monitoring and research.

DFO identified disturbance or removal of tributary stream channels of the Athabasca River and its tributaries as a cumulative effect upon water quality and fish habitat. To address this concern, DFO recommended that Shell and other regional operators examine incremental changes to streams and their predicted effects at a regional scale. DFO recommended that in combination with existing regional initiatives, new efforts were needed to detect cumulative effects on the regional aquatic environment.

DFO stated that its water quality concerns with respect to the project related to potential tailings disposal area seepage, possible degradation of water quality in Jackpine Creek, and uncertainties of EPL viability.

DFO expressed concern about water quality effects on fish health and fish tainting. DFO noted tailings seepage into the PCA as a concern, but it made no specific recommendations concerning the aquifer or its influence upon surface waters. It also raised uncertainties regarding synergistic or additive effects of interacting water contaminants as a concern. DFO recommended that Shell continue its participation in such organizations as RAMP, CEMA, and CONRAD and implement management strategies and recommendations of those groups. To determine the long-term ecological value of EPLs, DFO recommended the expansion of ongoing research.

To address concerns about cumulative effects on the water quality of the Athabasca River and its tributaries, DFO recommended that Shell participate in a site-specific long-term water quality monitoring program to detect changes in the Athabasca River. DFO supported Shell's continued participation in CEMA, RAMP, and CONRAD regional water quality monitoring and research.

10.8 Views of Alberta

AENV stated that tailings disposal area seepage could require additional monitoring and validation of EIA predictions. It believed that tailings seepage from the out-of-pit tailings disposal area would be limited to Shell's lease area, and seepage effects would be reduced by subsurface permeability conditions, collection ditches, and other mitigations. Groundwater monitoring would detect changes in the subsurface, should they occur. AENV stated that sulphur springs as identified by WBFN contributed relatively small volumes of water to the Athabasca River, so that the water quality of the river was not likely to be affected even under low-flow conditions.

AENV observed that with the exception of natural exceedances of dissolved oxygen and some metals, water quality of the Muskeg River generally complied with Alberta's Surface Water Quality Guidelines. AENV recognized that validation of water quality predictions would be necessary due to future landscape changes and modelling uncertainties related to hydrology and water quality parameters. AENV stated that it might require Shell to monitor surface water quality with some correlation to hydrologic observations. AENV expected Shell to continue its support of CEMA and to maintain work schedules for the development of regional water quality objectives.

10.9 Views of the Panel

The Panel acknowledges that matters related to tailings dike stability or design for flood conditions are subject to approval by AENV. The Panel also notes that Shell will submit detailed engineering designs of the out-of-pit tailings disposal area for technical review and evaluation by AENV for matters of geotechnical stability, hydrology, and public safety.

The Panel understands that water quality predictions of the project are subject to several uncertainties related to modelling assumptions, modelling techniques, baseline data, hydrologic conditions, containment of contaminants, and establishment of closure drainage on reclaimed lands. The Panel recommends that AENV include a condition in the EPEA approval requiring Shell to develop and implement monitoring programs for sediment and water quality for waters that may be affected by the project. The Panel expects Shell to design the program with input from AENV, EC, DFO, and other stakeholders to address such issues as geographic and temporal scope, synergistic effects, scientific precision, and repeatability. The Panel is mindful of the long time frames for tailings seepage water to reach surface waters. Therefore it recommends that AENV ensure that monitoring plans are designed to ensure early detection of potential water quality changes in groundwater and surface water due to their interactions.

The Panel accepts AENV's position that the EPEA licence conditions for the project for the monitoring of surface and groundwater quality and quantity will address potential effects of saline and sulphur springs on the Athabasca River.

The Panel finds that the project has potential to increase the PAI, both locally and to a lesser extent regionally, with possible effects on critical load exceedances of water bodies. Therefore, the Panel recommends that AENV condition any EPEA approval for the project to require monitoring of acid deposition on water bodies. The Panel also expects that Shell will support RAMP and WBEA to ensure monitoring and management of acid deposition effects on ecological receptors in the region.

The Panel concludes that the project is not likely to cause significant adverse environmental effects on surface water quality, provided that the mitigation measures and the recommendations of the Panel are implemented.

11 SURFACE HYDROLOGY

11.1 Views of Shell

Shell assessed environmental changes to surface hydrology in the local and regional study area attributed to such activities as muskeg and mine dewatering, mining, relocation of tributary streams, water withdrawals from the Athabasca River, filling and operation of EPLs, and release of waters from reclaimed land surfaces. It also assessed changes to surface hydrology for potential effects on fish and aquatic organisms and on human health. In all cases, Shell predicted that environmental effects on hydrology as a result of the project would not be significant or adverse to the environment. Shell did not complete a cumulative effects assessment for surface hydrology, since the project effects on hydrology were negligible. Shell's conclusions regarding project effects were contingent upon mitigation measures being successfully implemented by Shell and other operators.

Shell stated that several tributary streams of the Muskeg River would be disturbed or excavated during the course of the project. Figure 2 shows the area of the Muskeg River drainage basin and some tributaries of the Muskeg River. Surface waters from seven tributary streams of the Muskeg River would be affected by mining. A new outlet to Kearl Lake and the Khahago surge facility would be constructed. Jackpine Creek would remain essentially unchanged, as it had high value for fish habitat. At mining closure, three large EPLs were planned, two of which would contain water-capped tailings. The lakes would function for flow attenuation and bioremediation of flows from reclaimed lands.

Shell consulted extensively over two years with a number of the local communities and groups to address environmental concerns, including water resource management, which was of prime importance. Several mitigation measures for reducing environmental effects on water, such as routing of diversions, setback distances, on-site storage of water, and monitoring programs, were addressed through agreements and action plans. Shell identified several initiatives it supported through CEMA and RAMP for the collection of data and management of cumulative effects on water resources. From its recent operating history as a partner in the Albian Sands Muskeg River Mine, Shell submitted additional water resource data to support the project application.

Shell stated that the Muskeg River was one of the most heavily studied rivers of the mineable oil sands region. This benefited Shell by providing a wide assemblage of baseline and EIA data for surface water hydrology. Shell adopted the HSPF to evaluate the study area hydrology and predict flows at key intervals during the life of the project and other existing and planned oil sands projects. Shell used historical records for statistical analyses of Athabasca River discharges and a steady-state model of the Athabasca River in assessing dispersion flows and constituent concentrations. Shell used a mass balance modelling of input and output flows to predict conditions of EPLs.

Shell advanced approaches and mitigation measures for reducing effects of the project upon water resources. These are presented in Section 9: Water Management.

Shell supported the work of CEMA's IFN subgroup in its efforts to develop by 2005 a management system based on ecological, social, and economic values. Shell did not support the development of an interim IFN flow guideline, as advanced by some interveners. Shell submitted evidence of the RAMP (2003) five-year review report, which concluded that between 1957 and 2001 there were no statistically significant trends in the annual maximum flows, minimum flows, or water yields of the Athabasca River.

Shell also addressed issues of existing and planned oil sands mining within the Muskeg River drainage basin and their cumulative effects. It predicted no significant adverse effects to the hydrology of the drainage basin.

Shell predicted that the project would not affect Kearl Lake or McLelland Lake. However, it stated that if effects were attributable to the project, it would implement mitigation measures. It agreed to continue its monitoring efforts through RAMP so that annual monitoring of the lakes would occur. Shell agreed to prepare a monitoring plan for Kearl Lake to collect baseline data during the predevelopment of the project. In its agreement with ACFN, Shell committed to assist ACFN in a plan to restore Richardson Lake (located near Lake Athabasca) for fish spawning.

11.2 Views of MCFN

MCFN stated that its agreement with Shell addressed low flows in the Athabasca River. The agreement required Shell to provide 30 days of on-site water storage to reduce withdrawals from the Athabasca River during low-flow periods. MCFN said that an interim IFN was required for the Athabasca River. MCFN also expressed concerns about cumulative reduction of water quality and quantity in the Athabasca River.

11.3 Views of ACFN

The ACFN agreement with Shell identified several water resource issues. ACFN asked Shell to address the issue of low flows in the Athabasca River and to maintain the river's health, integrity, and sustainability. ACFN recommended to Shell that it involve ACFN members in the design of monitoring programs (e.g., water resources) and development of thresholds for use in Shell's management program. Regarding Kearl Lake and McLelland Lake, ACFN sought assurances from Shell that both lakes would be monitored and that no impacts would occur from the project. ACFN was concerned about the falling water levels of Richardson Lake due to its importance to fish spawning.

11.4 Views of Fort McKay

In closing argument, Fort McKay recommended that the Panel establish timelines for CEMA to develop and recommend interim management guidelines for IFN of the Athabasca River. For protection of the Athabasca River, Fort McKay asked Shell to agree to an AENV licence clause limiting withdrawals for flows below 115 m^3/s. It believed that AENV should have the ability to amend Water Act licences based on the results of CEMA's recommendations regarding IFN. Fort McKay sought assurance from Shell that the project would not impact Kearl Lake. Fort McKay asked Shell to facilitate accelerated work by CEMA and adopt measures to protect the Muskeg River basin before start-up of the project.

11.5 Views of SCC

SCC requested that the Panel suspend decisions for new developments in the Athabasca region, including the Jackpine project, pending a full assessment of the true cumulative effects of those projects. Furthermore, SCC requested that the Panel delay any decisions concerning the project or its water withdrawals until 2005, when results of the CEMA IFN study would be available. According to SCC, Shell's annual water withdrawals and those of other oil sands operations had downstream implications for the Peace-Athabasca Delta and the Mackenzie River Basin Transboundary Master Agreement. Withdrawals from the Athabasca River would negatively affect a river that had already experienced decreased flows from climate change. SCC recommended that Shell be required to re-evaluate its water assumptions for flood protection and tailings management, because it had failed to account for monthly flow variability of the Athabasca and Muskeg Rivers and for a declining flow trend in the past decades.

11.6 Views of Canada

DFO recommended that IFN for the low-flow ice-cover period be established for the lower Athabasca River prior to Shell requiring water withdrawals for the project.

11.7 Views of Alberta

AENV disagreed with interveners that Athabasca River flow had experienced a historical decline. AENV presented a statistical analysis that did not show a statistically significant trend of declining flows. The water allocations Shell was applying for, including all existing, approved, and planned maximum annual water withdrawals, were 6.2 per cent of the river's total annual flow.

11.8 Views of the Panel

The Panel accepts that the project will result in substantial hydrological and landscape change in the project area, and it accepts the key commitments Shell has made to mitigate effects on the environment. In areas such as IFN, watershed management, EPLs, and the compensation lake, the Panel recognizes that a number of uncertainties exist. However, the Panel finds that with current regulatory processes and the efforts of regulators and CEMA to develop leading-edge environmental objectives and management systems, the uncertainties are manageable and acceptable. The Panel does not believe that decisions regarding the project should be deferred. The Panel believes that regulatory requirements, adaptive management processes, monitoring and mitigation measures, and implementation of the Panel's recommendations provide sufficient protection for the environment.

The Panel accepts that within current and future Water Act licences, AENV has authority to amend licence terms and conditions. The Panel supports DFO's recommendation that an IFN management system be established for the lower Athabasca River prior to Shell requiring water withdrawals, and it recommends that DFO and AENV consider IFN objectives and management approaches in its approvals for the project.

The Panel notes that Shell stated that a management system was to be developed for maintaining the Muskeg River drainage basin integrity. This matter is of particular importance and is addressed further in Section 17. The Panel recognizes the efforts of Shell to maintain key tributaries of the Muskeg River, such as Jackpine and Muskeg Creeks, as well as Shell's efforts to maintain the Muskeg River as a key tributary of the Athabasca River. The Panel believes there would be a benefit in evaluating the effectiveness of corridors with respect to wildlife and watershed management. The Panel therefore recommends that ASRD require Shell to also consider the widths and types of buffer zones for benefits to watershed management when evaluating wildlife corridors. This requirement could be met by Shell on its own or in cooperation with other stakeholders.

The Panel is aware of past EUB decisions on oil sands development that expressed concerns about the proliferation of lakes containing water-capped tailings in reclaimed landscapes. As noted in Section 8, the Panel has directed Shell to continue to develop alternative technologies for tailings management. The Panel believes that opportunities will emerge for Shell through such work to optimize the project further by reducing environmental effects on surface waters and the land base.

The Panel notes that Shell stated that Kearl Lake would not be adversely affected by changes to groundwater or alteration of the outlet of Kearl Lake. The Panel recommends that AENV require Shell to conduct or support monitoring of water levels in Kearl Lake to validate the predictions made in the EIA.

The Panel concludes that significant adverse environmental effects from the project on surface water hydrology are unlikely to occur, provided that the mitigation measures and the recommendations of the Panel are implemented.

12 AQUATIC RESOURCES

12.1 Views of Shell

Shell evaluated the effects of the project on fish and fish habitat, fish health, and tainting in conjunction with existing and planned projects. It also examined potential effects of air emissions on water bodies and aquatic resources.

With respect to fish and fish habitat, Shell indicated that the project would result in the removal of a number of creeks. Additionally, Muskeg Creek would be altered and reconstructed over the life of the project. Upon closure of the project, the redesigned Muskeg Creek would discharge to the Muskeg River about 2 km downstream of its existing discharge channel, thereby reducing the flow in that 2 km reach of the Muskeg River. Shell deemed the impacts of the project prior to compensation measures to be long term and of low magnitude for the Muskeg River and to be long term and of moderate to high magnitude for the tributaries of the Muskeg River. However, in accordance with DFO's policy, Shell had developed an NNLP to offset the losses resulting from the project. As a result, Shell predicted that the residual impacts on habitat and subsequently on fish abundance would be negligible after implementation of the proposed compensation strategy outlined in the NNLP. Shell indicated that it would also implement a variety of mitigation measures to alleviate effects on fish habitat in areas not directly impacted by mine development.

Shell proposed a compensation lake as part of the NNLP. Shell proposed to locate the lake on Syncrude's Lease 34. Shell stated that it was presently negotiating an agreement with Syncrude to enable it to start construction of the compensation lake in 2005 in an area that provided an optimum balance between ore sterilization and environmental protection. Shell stated that it did not believe the lake was located on mineable ore, but it would complete additional drilling prior to construction of the lake. If it identified additional oil sands resource, Shell proposed to modify the footprint of the lake or apply to the EUB for approval to sterilize an oil sands resource.

In Shell's examination of the potential effects of predicted water and sediment quality and acidifying emissions on fish health, it concluded that the overall effect of the project on fish health would be negligible. However, one exception was that Shell predicted slightly higher concentrations of naphthenic acids in Jackpine Creek until 2040, at which time the peak and median concentrations would increase more substantially. Although Shell determined that the environmental consequence would be negligible, it acknowledged that there was uncertainty about the level of naphthenic acids that would result in chronic impacts on fish. Therefore, it noted that further follow-up work was needed to establish which naphthenic acids contributed most to toxicity and the concentrations at which this toxicity would occur.

Additionally, Shell assessed the effects of project-related tainting compounds on fish tissue. It concluded that effects would be negligible, but noted that its confidence in the prediction was low due to lack of laboratory studies that used aged or treated process waters.

Shell predicted that the overall effect of the project on benthic communities in water bodies, small streams, and the Muskeg River would be negligible, since the habitat lost to mine development would be recreated to achieve no net loss and the projected changes were relatively small.

12.2 Views of MCFN

MCFN emphasized its reliance on fish and game and noted that some of its members operated as commercial fishers on Lake Athabasca and at the mouth of the Athabasca River.

As part of the MCFN and Shell agreement, Shell committed to review environmental monitoring programs, including the aquatic resources program, with MCFN and to seek its input on the design and implementation of those programs through MCFN Industry Relations Committee representatives.

12.3 Views of Canada

EC noted that the Fisheries Act prohibited the deposit of deleterious substances into fish-bearing waters. It expressed concern regarding the potential of oil sands development to cause the tainting of fish tissue, which was prohibited under the Act. EC noted its participation in the fish tainting committee under CONRAD and commended the progress made by that committee.

Notwithstanding industry's commitment to the fish tainting program, EC acknowledged that it was concerned that the program might not address knowledge gaps, future research, and monitoring adequately. EC suggested that the program should address both project-specific and cumulative effects of oil sands development on fish tainting in the Athabasca River. EC therefore recommended that Shell ensure that the fish tainting program address the knowledge gaps it had identified and make suggestions for future research and monitoring.

DFO was also concerned about the potential of seepage from the tailings disposal area to taint fish or impact fish health. It stated that fish tainting models and the fish health assessment were derived from the results of the HSPF modelling. DFO noted that HSPF modelling used limited real data and, therefore, the level of uncertainty in predictions made by the model was relatively high. DFO recommended that the uncertainties associated with modelling be addressed in the NNLP. Furthermore, with regard to fish tainting, DFO recommended that Shell continue to participate in regional research and water quality monitoring initiatives that addressed the effects of water quality on aquatic resources.

DFO noted its concerns regarding the cumulative environmental effects on fish and fish habitat as a result of the successive elimination of watercourses and cumulative water withdrawals. The lack of baseline data on aquatic resources, coupled with the lack of functioning examples of replacement habitat similar to that proposed by Shell, increased its concerns. Furthermore, it pointed out that the NNLP did not address habitat losses resulting from Shell mining through the floodplain of the Muskeg River. DFO stated that the project would not result in significant adverse environmental effects, provided that the proposed mitigation and compensation measures were undertaken.

DFO believed that Shell had limited opportunity to replace the habitat loss with similar habitat in the same area, given the scale of watershed disturbance proposed. However, DFO stated that it would continue to work with Shell to develop an NNLP that would provide acceptable habitat compensation in the region. DFO would also continue to explore additional alternative compensation options, including off-site works and habitat enhancement projects to ensure no net loss of fish habitat. DFO recommended that all incremental change predictions and concerns be examined on a regional scale and recommended that Shell continue to participate in regional initiatives that facilitated the detection of cumulative effects on the aquatic environment. DFO had no concerns about the compensation lake being located off of Shell's lease. DFO stated that prior to issuing approval of the NNLP, it would require verification from Shell that it had an agreement with Syncrude and that the EUB had approved any oil sands resource sterilization.

DFO asked Shell to continue its participation in the MRWI subgroup and to adopt recommendations that might result from that group's initiative. DFO identified disturbance or removal of tributary stream channels of the Athabasca River and its tributaries as having a cumulative effect on water quality and fish habitat. DFO recommended that AENV and the EUB examine all incremental change predictions at a regional scale. DFO stated that in combination with existing regional initiatives, new efforts were needed to detect cumulative effects on the regional aquatic environment. DFO recommended that Shell participate in existing and new regional initiatives to detect cumulative effects on aquatic resources.

With regard to protecting existing fish habitat, DFO recommended that Shell provide a minimum setback of 100 m along Muskeg Creek upon closure to mitigate the potential impact of mining on riparian habitat and the ecological functioning of the creek. DFO stated that it would be satisfied with a 65 m buffer between the constructed channel and the mine pit, which would allow for the establishment of some riparian area along the diversion channel. A similar buffer of 65 m would be expected for the compensation lake during operations and one of 100 m upon closure.

DFO stated that it did not accept EPLs as compensation for fish habitat. It also noted that there were no functioning examples of EPLs on the landscape with which to verify Shell's prediction that EPLs would eventually be capable of providing aquatic habitat. It recommended that ongoing research into EPLs be continued and expanded to determine their ecological value.

12.4 Views of Alberta

Alberta noted that both water quality and quantity were fundamental to healthy functioning fish habitat. In its view, Shell's predictions of the project-specific and cumulative impacts on fish and fish habitat lacked certainty due to the uncertainties associated with the water quality and quantity models. However, Alberta believed that effects on fish populations and fish habitat would be negligible if Shell could successfully compensate for loss of fish habitat through the NNLP. ASRD noted that responsibility for the NNLP was DFO's and stated that it would continue to provide technical advice on the NNLP. ASRD recommended that monitoring for fish and fish habitat issues continue through groups such as RAMP. When asked whether RAMP was a sufficient monitoring program, AENV responded that the program was currently undergoing a peer review, which would identify any gaps and enable RAMP members to address them. With respect to baseline information, Alberta believed that adequate information pertaining to fish had been collected, but noted that additional information relating to benthic invertebrates would be beneficial.

12.5 Views of the Panel

The Panel acknowledges the concerns expressed by several interveners regarding fish habitat losses and the potential impacts of the project on aquatic resources in the region. The Panel notes DFO's evidence that the impacts on fish and fish habitat can be mitigated through the implementation of mitigation measures, monitoring, and follow-up and by ensuring adequate compensation for habitat losses. The Panel is satisfied that no net loss can be achieved effectively. Nevertheless, the Panel believes that a strong monitoring plan is critical to ensure that fish and fish habitat effects are understood. The Panel recommends that DFO, in consultation with ASRD, AENV, EC, and regional stakeholders, require Shell to develop and implement a comprehensive monitoring program relating to fish and benthic macroinvertebrates.

The Panel notes that Shell's proposed compensation lake would be one of the first of its kind in the oil sands region. The Panel is aware that similar lakes may be proposed in the region to compensate for aquatic habitat lost due to oil sands development. As a result, the Panel recognizes that valuable knowledge could be obtained from this large-scale example of a compensation lake. Therefore, the Panel recommends that DFO require a report from Shell on its monitoring results relating to the compensation lake and share those findings with other stakeholders in the region. DFO should consider requiring Shell to monitor for fish abundance, community structure, and operational results of the compensation lake with regard to hydrological regimes and its responses to high- and low-water events.

The Panel understands that Shell will be completing additional drilling to determine if the proposed compensation lake location would impact oil sands resources. The Panel notes that if drilling indicates a mineable resource, Shell will be required to either relocate the lake or apply to the EUB for resource sterilization.

The Panel notes the lack of information, specifically the uncertainty around naphthenic acids, and the subsequent uncertainty surrounding the issue of fish tainting. The Panel notes Shell's participation in regional initiatives intended to address issues of water quality and fish health, and it is encouraged by the work of the fish tainting committee under CONRAD. It also notes EC's evidence that the CONRAD program may not adequately address knowledge gaps. The Panel is concerned that the information may not be generated in a manner that addresses concerns raised in the proceedings. The Panel notes that the issue of naphthenic acids and their potential impacts on water quality and fish tainting has been known for 20 years. While the Panel recognizes the complexity of this issue, it believes that a higher priority should be placed on understanding it.

The Panel recommends that AENV and ASRD, in consultation with DFO and EC, require Shell to conduct follow-up studies on potential impacts of fish tainting compounds. Furthermore, the Panel encourages DFO and EC to increase their participation in the CONRAD fish tainting program so that the information gaps and research needs identified can be addressed.

The Panel concludes that with the implementation of mitigation measures and the Panel's recommendations, the project is unlikely to result in significant adverse environmental effects on aquatic resources.

13 GROUNDWATER

13.1 Quaternary

13.1.1 Views of Shell

Shell indicated that groundwater from the overburden overlying the mine pits would be removed and released to the surface water drainage system to help mitigate the interception of natural baseflow. Shell predicted that groundwater level in the overburden would recover to very near premining levels and that overburden dewatering activities would not affect groundwater quality. Shell indicated that changes in water levels might affect wetlands and vegetation surrounding the mine pit but that any impacts would be negligible. It stated that it would implement a monitoring program to assess the impacts and validate its conclusions.

Shell indicated that tailings pore water would seep downwards through the tailings disposal area and into the shallow Quaternary deposits. Shell predicted that tailings water seepage would degrade natural groundwater quality, but that the effect of seepage would be limited to the area immediately beneath and adjacent to the tailings disposal area. Shell suggested that certain mechanisms act to reduce solute concentrations in groundwater and thus reduce concentrations and delay breakthrough. Shell stated that it would construct a 6 m deep perimeter ditch to intercept seepage flow from the tailings disposal area, but that some seepage would discharge to the ground surface between the tailings area and Jackpine Creek and that half of this seepage would enter the creek. Shell indicated that some tailings backfill seepage would migrate up from the basal aquifer through the Quaternary deposits into the Muskeg River and through Quaternary deposits into the Muskeg Creek diversion in the far future. Shell stated that with appropriate mitigation, the effects on surface water quality would be negligible. Shell stated that it was planning a groundwater and surface water monitoring program to assess whether there were connections between groundwater and surface water.

Shell indicated that it planned additional drilling in and around the perimeter of the external tailings disposal area for the design of the tailings dike, as well as within the mining area. Shell stated that this information would provide additional information on the Quaternary deposits.

Shell stated that the PCA transected six oil sands leases and had been traced over a length of 77 km. Shell stated that within the project area, the channel was covered with about 10 to 30 m of till, was about 2 km wide, and ranged in depth to more than 50 m. Shell made a number of interpretations regarding groundwater flow within the PCA. In its EIA, Shell stated that based upon the available data, groundwater flow along the channel appeared to be from south to north. Later Shell indicated that groundwater was preferentially funnelled into the PCA from adjacent lower permeability sediments and groundwater flows along the length of the channel, which acted as a conduit for groundwater flow. At the hearing, Shell said that much of the groundwater that entered the PCA in fact passed through it transversely and then back into Quaternary deposits or the McMurray formation on the northwestern flank of the PCA and that the regional flow was generally towards the west and north.

Shell stated that it would use pumping wells to dewater the PCA in the vicinity of pit highwalls in order to stabilize the pit walls and minimize seepage into the mine. Shell predicted that PCA dewatering would affect groundwater levels and flow patterns during mining but that it expected groundwater levels to recover after dewatering ceased. Shell said that it would monitor the effects of dewatering.

Shell stated that the channel was protected by a layer of lower permeability till beneath the tailings disposal area, which would act as a natural liner. Shell predicted that during development, seepage from the external tailing disposal area would migrate downward into the PCA and then toward the dewatering wells. Shell indicated that it expected that initially the affected groundwater would have a chemical composition representing some mixture of the tailings seepage and the natural PCA water chemistry. Shell indicated that once dewatering ceased, the plume of tailings-affected water would remain within the PCA west and east of the tailings disposal area. Shell indicated that tailings seepage water would begin to migrate to the west toward Jackpine Creek and north toward the east EPL. It predicted that the primary areas affected would be limited to within 1 km of the external tailings disposal area. Shell indicated that over time the proportion of tailings seepage would increase until groundwater chemistry in the affected areas approached the same composition as undiluted tailings seepage. It also indicated that changes in groundwater quality would be long term and irreversible, but it did not expect to see significant effects on the PCA due to tailings disposal area seepage. Shell stated that the tailings sand seepage water composition would be within the natural variation of groundwater quality in the PCA and maintained that the water would still be classified as usable. Shell believed that its predictions regarding tailing disposal area seepage were conservative and indicated that it did not foresee any cumulative impacts from tailings seepage into the PCA if other developments in the area proceeded.

Shell stated that while some CT was consolidating, it would express pore water into portions of the PCA and that low-water levels during and shortly after dewatering would increase the tendency for CT pore water to migrate into the PCA. However, Shell indicated that it expected only minor groundwater exchange between the tailings and the PCA. Shell stated that as water levels in the PCA returned to predevelopment levels, seepage from CT cells would decrease to negligible rates.

To minimize the impacts to the PCA, Shell indicated that it had readjusted the mine pit limits to protect the integrity of the channel at the expense of leaving some of the ore in the channel. Shell noted that it would continue to refine and optimize the mine plans to look at the ultimate location of the pit wall and balance mining cost and PCA encroachment. Shell indicated that it would be doing additional work to design a system of depressurization wells and would evaluate its dewatering requirements.

Shell indicated that it had investigated lining the tailings disposal area to limit seepage to the PCA but found that did not provide an environmental benefit; therefore, Shell had not proceeded with a more rigorous evaluation. Shell indicated that a liner might, in fact, force the tailings disposal area seepage waters to the surface sooner and with greater environmental impacts. Shell summarized various adaptive management strategies for project effects on the Quaternary groundwater regime. Shell stated that if certain areas required protection from drawdown as a result of overburden dewatering, it might be possible to install locally a grout wall or low permeability barrier to groundwater flow. Shell indicated that if drawdown as a result of PCA dewatering affected wetlands or surface water bodies, it might consider reinjection of water in sensitive areas, change the sequencing and rates of dewatering, or manage stream diversions to allocate surface water release to sensitive areas. Shell stated that adaptive management strategies to deal with seepage from the tailings disposal area might include the installation of a drain system or a grout curtain, whereas strategies to deal with in-pit tailings might include the installation of a drain system or a reactive wall or the modification of surface drainage patterns to manipulate groundwater recharge and discharge areas and flow patterns.

Shell stated that it had established cooperation agreements with ExxonMobil and Syncrude and that none of the companies had plans to conduct a regional groundwater study of the PCA. Shell also stated that it had completed a conceptual groundwater-monitoring plan and would work with stakeholders to refine the plan. Shell further stated that it would file the revised groundwater-monitoring plan as part of its EPEA approvals. Shell noted that a regional groundwater-monitoring program in the oil sands mining area was not proposed by individual proponents or CEMA. Shell indicated that it could address regional issues through cooperation agreements with adjacent leaseholders.

13.1.2 Views of MCFN

MCFN stated that its agreement with Shell provided for

- MCFN to review and have input on Shell's proposed groundwater-monitoring program and its implementation,
- MCFN to review the results of monitoring programs to validate the effectiveness of mitigation measures and the correlation between monitoring results and EIA predictions, and

- Shell to collect additional data on groundwater resources and aquifers in the Muskeg River basin.

13.1.3 Views of ACFN

ACFN's agreement with Shell required Shell to

- involve ACFN in the design of monitoring programs,
- determine threshold values that would trigger adaptive management actions, and
- provide ACFN with monitoring results and a comparison with EIA predictions.

13.1.4 Views of Fort McKay

Fort McKay's agreement with Shell provided for the involvement of Fort McKay in the design of the groundwater-monitoring network and in the adaptive management process, including the development of triggers that would result in mitigation actions.

13.1.5 Views of Alberta

AENV stated that it considered seepage from the external tailings disposal area into the PCA to be an impairment of the aquifer. AENV believed that the water within the PCA would be considered a usable groundwater resource even after seepage effects modified its composition. AENV stated that it might include a condition requiring Shell to submit a detailed mitigation plan to limit the lateral extent and water quality effects of seepage prior to the first use of the tailings disposal area. AENV stated that it might also include conditions in any EPEA approval requiring Shell to collect additional data on the aquifer and to confirm Shell's predictions on the effects of tailings disposal area seepage. AENV indicated that long-term effects on the PCA could be minimized and limited to the mine lease boundaries through a comprehensive groundwater monitoring program and effective mitigation process managed through the EPEA process.

With respect to project-specific considerations, AENV indicated that a regional groundwater study on the PCA was not necessary but that the information provided by a regional study might be useful.

AENV indicated that the conceptual groundwater monitoring plan was detailed and addressed several of the aquifers potentially impacted, including those present in the overburden, the PCA, and the basal aquifer. AENV indicated that the monitoring plan included a substantial list of parameters that would be monitored and that the plan was appropriate, although some revisions might be required.

13.1.6 Views of the Panel

The Panel recognizes that tailings seepage will change water quality within the Quaternary aquifers in the Shell lease area. The Panel accepts Shell's and AENV's position that groundwater within these aquifers will remain usable even after seepage water has entered them. The Panel also accepts that Shell has incorporated conservative assumptions into its seepage models. The Panel notes that AENV indicated that long-term effects on the PCA could be managed through the EPEA process. The Panel also notes that AENV stated that it might include a condition in any EPEA approval requiring Shell to submit a detailed additional mitigation plan to limit the lateral extent and water quality effects of seepage prior to the first use of the tailings disposal area. The Panel believes that some mitigation options may be forsaken once construction of the disposal area is complete. Therefore, the Panel recommends that AENV consider requesting Shell to provide, prior to construction, additional mitigation plans to limit external tailings disposal area seepage. The Panel supports AENV's plans to incorporate monitoring and mitigation requirements for tailings seepage effects in any EPEA approval.

The Panel notes Shell's commitment to continue to investigate the Quaternary deposits in the external tailings disposal area and sees this as an opportunity for Shell to continue to refine its seepage effects conclusions. The Panel therefore recommends that AENV's Dam Safety Branch require Shell to include updated seepage modelling results, Quaternary deposits mapping, monitoring plans, and mitigation measures in the tailings disposal area detailed design report.

The Panel notes that Shell has redefined its mine pit limits to protect the integrity of the PCA. The Panel recognizes that the final mine pit limits have not been established and may differ from those currently proposed after additional drilling is completed. Revised pit limits might compromise the integrity of the PCA. While the Panel is prepared to accept that seepage from in-pit tailings will be negligible under the current mine plan, it is conceivable that contamination of the PCA could occur if Shell revises its plans to include mining into the channel. The Panel directs that Shell provide a report, for EUB approval, detailing its mine plans near the PCA five years prior to mining in this area to allow for the consideration of resource recovery issues and environmental impacts. The report shall include the proposed location of the pit limits and their proximity to the PCA, as well as a description of any mitigation that would be completed to minimize the impact of mining near the PCA.

The Panel notes Shell's commitments to involve stakeholders in the design and implementation of its groundwater monitoring program, as well as Shell's commitments to review the results of the monitoring program with these stakeholders in order to assess the validity of its EIA predictions. The Panel recognizes the value of such commitments in ensuring that all parties understand project impacts.

The Panel recognizes that the PCA is a potentially significant groundwater resource of usable water that Shell's and other oil sands developments are likely to impact. The Panel understands that both Shell and AENV believe that a regional groundwater study of the PCA is not necessary for project-specific considerations. The Panel also notes that Shell indicated that it did not foresee any cumulative impacts from tailings seepage into the PCA should other development in the area proceed. However, the Panel believes that there is value in better understanding the nature of this groundwater resource before development begins. The Panel is concerned that the Syncrude and ExxonMobil developments could also impact the PCA. Therefore, the Panel recommends that AENV incorporate conditions in its approval requiring Shell, in conjunction with other developers, to define and carry out a regional groundwater study of the PCA in order to evaluate the regional nature of this groundwater resource. The Panel believes this assessment should be carried out before mining begins in the vicinity of the PCA.

The Panel concludes that with the implementation of mitigation measures and the Panel's recommendations, the project is unlikely to result in significant adverse environmental effects on the Quaternary groundwater regime.

13.2 Basal Aquifer

13.2.1 Views of Shell

Shell stated that a water-saturated basal aquifer was present between the top of the Devonian Formation and the base of the McMurray Formation. Shell indicated that the basal aquifer must be depressurized prior to mining to ensure pit floor and pit wall stability. Shell maintained that the effects of depressurization would extend beyond the immediate vicinity of the mine site. It said that drawdown in the basal aquifer could also produce drawdown in overlying formations, but that depressurization would not significantly affect groundwater elevations in shallow Quaternary deposits. Shell predicted that groundwater discharge to the major rivers in the area would decrease as a result of basal aquifer depressurization, but that the predicted changes represented only small fractions of the respective flows in each stream. Shell indicated that deep seepage beneath the external tailings disposal area would increase as a result of depressurization. Shell also indicated that downward seepage from the tailings disposal area into the basal aquifer might result in a deterioration of groundwater quality in the aquifer in the far future. Shell stated that if depressurization caused unexpected effects, it might adjust the location of dewatering wells or pumping rates to reduce the magnitude of drawdown or it might undertake reinjection of depressurization water back into the basal aquifer.

Shell stated that in-pit tailings backfill would be in direct contact with groundwater in the McMurray Formation and that tailings backfill water would migrate downward through the bottom of mine pits and into the basal aquifer. Shell stated that the resulting deterioration in basal aquifer groundwater quality would be a long-term phenomenon. It suggested that tailings seepage could migrate through the basal aquifer into the west EPL. Shell predicted that in the far future, a plume of tailings-affected water would be present in the basal aquifer, extending from the project to the Athabasca River, and that seepage-affected water would migrate upwards from the basal aquifer through Quaternary sediments into the Muskeg River. Shell indicated that it would conduct groundwater monitoring of the basal aquifer. Shell stated that adaptive management strategies to control seepage flow included the installation of a drain system to capture affected groundwater, the installation of a reactive wall to prevent further migration of affected groundwater, and modifications to the surface drainage pattern to manipulate groundwater recharge areas, flow patterns, and discharge characteristics.

Shell indicated that it would conduct exploration drilling and continue to define the extent of the basal aquifer based on those results. Shell stated that within the mining design effort, it would look at additional information in the areas of basal water quality and depressurization volumes to make sure that the depressurization design was correct. Shell committed to use basal aquifer water in the extraction process regardless of the total dissolved solids (TDS) value of that water.

13.2.2 Views of the Panel

The Panel recognizes that, based on TDS values, water within the basal aquifer could be considered usable groundwater and that TDS values and many chemical parameter concentrations in basal aquifer water exceed the values anticipated for CT and tailings sands pore water seepage. However, certain concentrations anticipated for metals in the CT pore water seepage exceed maximum acceptable concentrations for drinking water quality. The Panel understands that seepage from in-pit tailings would flow into the basal aquifer and form a plume discharging to the Muskeg and Athabasca Rivers in the far future, and potentially to the west EPL. The Panel notes Shell's statement that certain mechanisms act to reduce solute concentrations in groundwater and delay breakthrough. The Panel recognizes that Shell has proposed monitoring programs to validate its groundwater model's predictions and plans on conducting monitoring of basal aquifer water quality in conjunction with its depressurization activities. The Panel notes that Shell has identified adaptive management strategies to deal with any unexpected results.

The Panel expects Shell to meet its commitment to use basal aquifer depressurization water in the extraction process, regardless of TDS.

The Panel notes that a number of groups are collecting data in order to assess the regional impacts of development in the oil sands area on air, surface water, and wildlife, but that no group appears to be assessing the regional impact of development on groundwater. In light of the number of developments in the area, as well as the scale of development, the Panel believes that such an initiative would be valuable in assessing all potential impacts. The Panel recognizes that Shell indicated that it could address regional groundwater issues through cooperation agreements with adjacent leaseholders and that it will undertake monitoring of project-scale impacts on groundwater. The Panel also recognizes that no single leaseholder should be tasked with undertaking a regional groundwater monitoring study. The Panel recognizes that an additional recommendation to regional working groups to undertake such an initiative may not be feasible, given their current workloads. The Panel believes that a regional working group examining groundwater issues should be considered by AENV.

The Panel concludes that with the implementation of any necessary mitigation measures, the project is unlikely to result in significant adverse environmental effects on the basal aquifer groundwater regime or connected surface water bodies.

14 AIR EMISSIONS

14.1 Views of Shell

Shell predicted that the project would increase total regional sulphur dioxide (SO_2) levels by only 0.1 per cent. Shell stated that although the maximum predicted 1-hour ground-level SO_2 concentrations would exceed *Alberta Ambient Air Quality Guidelines* (AAAQG) levels in all emission scenarios (baseline, application, and planned), the predicted differences between maximum SO_2 concentrations for the baseline and application cases were negligible, indicating that the project had little influence on these exceedances.

Shell predicted that the project would increase total regional nitrous oxides (NO_x) emissions from 218 to 241 tonnes per day (t/d). Shell's air quality modelling predicted exceedances of AAAQG for annual nitrogen dioxide (NO_2) in the local and regional study areas for all assessment scenarios. Shell advised that the contribution of the project to the exceedances was small and that predictions of NO_2 tended to be conservative to account for the uncertainty related to predicting ambient NO_2 levels.

Shell committed to develop the project with the following NO_x mitigation measures: a mine fleet that met applicable emission standards at the time of purchase, optimization of travel distances for the mine fleet, effective road and vehicle maintenance programs, use of efficient turbine technology, and low-NO_x technologies for boilers and turbines.

Shell submitted that emissions from the project would not significantly contribute to acidification of soils and water in the region. Shell stated that its analysis was conservative because it had used maximum air emissions for all projects. It maintained that the dispersion model predictions of emissions were founded upon conservative assumptions and that the predicted level of acidifying emissions and PAI values were significantly overstated in the EIA.

Shell noted that there were three tools to manage acidification in the region. One was the acidification management plan presented to CEMA on September 30, 2003. Shell believed that the implementation of this plan would minimize the risk of acidification occurring in the region. The second tool was a comprehensive ambient deposition and environmental effects monitoring program for acidification that was already in place under WBEA. The third tool was an annual monitoring program completed by RAMP to monitor potential changes in alkalinity in water bodies.

Shell predicted that the 24-hour-average concentrations of particulate matter size 2.5 micron ($PM_{2.5}$) would exceed the Canada Wide Standard (CWS) of 30 micrograms per cubic metre ($\mu g/m^3$) in two of the regional communities assessed, Conklin in all emissions scenarios (baseline, application, and planned), and Fort McMurray for the planned scenario. Shell attributed these exceedances in part to community sources of $PM_{2.5}$. Shell believed that its modelling for $PM_{2.5}$ was conservative.

Shell committed to funding a diesel particulate filter project through the Clean Air Strategic Alliance (CASA) and, if it was successful, to explore the feasibility of using the filters on buses in the Fort McMurray area.

Shell stated that it shared the widespread concern that GHGs were leading to changes in the global climate. Shell advised that it supported the commitment by Royal Dutch/Shell Group to cut emissions from GHGs from its global operations by the amount that would meet or exceed Kyoto emissions reduction targets out to the year 2010. Shell noted that it had set voluntary targets for its oil sands unit, with a goal to be less carbon dioxide (CO_2) intensive than the most likely alternative, which was imported crude on a full-cycle basis. It stated that this goal had led to a voluntary reduction target of 50 per cent by 2010 for the Muskeg River Mine. Shell stated that it was presently working with its stakeholders and the Shell Canada Climate Change Advisory Panel to assess voluntary targets for the project, and it further committed to put in place a GHG management plan to reduce emissions over time. Shell also committed to employ the best commercially available technology to minimize GHG emissions. Shell stated that it was committed to meeting the future requirements of Alberta and Canada with respect to GHGs.

14.2 Views of OSEC

OSEC stated that Shell had committed to funding research on a diesel engine after-treatment device and a diesel particulate filter project.

14.3 Views of SCC

SCC was concerned with the EIA results that indicated that the PAI was predicted to exceed critical load for sensitive soils in a significant area, some 288 000 hectares (ha). SCC understood that acidification could lead to problems in forest growth and to acidification of streams and lakes. SCC also stated that acidification in soils could lead to leaching of metals and create other environmental and health problems.

SCC believed that areas in Saskatchewan might be affected by acid deposition, but agreed that the worst air quality effects would be in the local study area (LSA).

SCC stated that it understood that Canada had committed to Kyoto, which called for a 6 per cent reduction of GHGs. It also understood that the Kyoto target was only the first step and that further reductions up to 60 per cent were needed. SCC believed that by approving long-term investment in fossil fuels, such as this project, Canada would have a difficult time meeting its commitments, and therefore it believed the project approval should be denied.

14.4 Views of Canada

EC recommended continuous monitoring of NO_x near the project to validate near-field modelling of baseline and cumulative environmental assessment conditions and agreed that WBEA would be the most appropriate group to implement this recommendation.

EC noted that preliminary total acid deposition modelling indicated that long-range transport into Saskatchewan was likely causing wet and dry acid deposition at levels well below the thresholds for harmful effects. EC recommended that Shell comply with the acidification management plan developed by CEMA.

EC also recommended that regional stakeholders participate in programs to design and implement a more rigorous wet and dry deposition monitoring program, and it believed that the Terrestrial Environmental Effects Monitoring (TEEM) committee would likely implement this recommendation.

EC recommended that regional stakeholders participate in programs to initiate particulate matter and precursor monitoring. EC believed that the Trace Metal Air Contaminants (TMAC) subgroup could design an action plan to fill in the remaining knowledge gaps with respect to particulate matter and that WBEA could implement appropriate long-term monitoring of particulate matter and precursors.

Natural Resources Canada (NRCAN) noted that the oil sands industry reduced its GHG emissions intensity by about 30 per cent and that the industry had forecast that between 1990 and 2010 it would decrease its emission intensity by about 45 per cent. It noted that the oil sands industry had been designated as a large industrial emitter under Canada's Climate Change Action Plan announced in November 2002. EC and NRCAN submitted that Shell would be required to comply with emission intensity targets once established by the Large Industrial Emitters Program under Canada's Climate Change Action Plan.

14.5 Views of Alberta

AENV stated that its policy was to control SO_2 and NO_x emissions to the lowest practicable level through the use of the most appropriate pollution prevention and control technologies. AENV stated that it might include conditions in the EPEA approval requiring Shell to collaborate with WBEA to support an ambient monitoring program that would validate predicted SO_2 and NO_x concentrations.

AENV believed that Shell's modelling results predicting ambient NO_2 emissions indicated that NO_x emissions from the mine mobile equipment should be further studied and emissions further minimized. AENV recommended that Shell and other oil sands mine operators consider an industry undertaking to confirm the source emissions of mobile fleets and review the minimization of emissions from mobile sources. AENV stated that it might include conditions in the EPEA approval requiring Shell to demonstrate that all replacement mine vehicles would meet the latest vehicle emission standards and that they would be equipped with effective emission control technology.

AENV stated that continued ambient monitoring in the region to determine the concentration of acidifying substances in air was a critical component in quantifying and assessing any risk of acidification in regional soils and water bodies. AENV noted that long-term monitoring would be needed to measure more precisely and accurately the effects of wet and dry deposition of sulphur and nitrogen on the environment. AENV stated that it might include conditions in the EPEA approval requiring Shell to participate in ongoing regional environmental management and monitoring initiatives to address acid deposition. It added that it might also include conditions requiring Shell to implement CEMA recommendations for an acidification management framework.

AENV believed that the assumptions Shell used in its $PM_{2.5}$ modelling were conservative and therefore it was unlikely that the CWS would be exceeded. It noted that the modelling results did suggest a need for $PM_{2.5}$ monitoring in communities to confirm Shell's predictions and determine if follow-up management actions were warranted. AENV stated that it might include conditions in the EPEA approval requiring Shell to collaborate with WBEA on enhanced ambient air monitoring for $PM_{2.5}$ in the communities of Conklin and Anzac in order to validate the modelling.

AENV stated that it was committed to reducing GHG emissions and contributing to an effective approach for responding to the risks of climate change. AENV noted that Alberta's action plan provided a framework for reducing GHG emissions while maintaining economic competitiveness.

AENV stated that it might require Shell to submit an annual GHG emissions summary that would include total GHG emissions for the year, emissions intensity, and calculation methodologies used. The GHG summary would describe gross emissions, as well as net emissions, should Shell use offsets to meet any performance targets. AENV indicated that Shell would be required to monitor and report in accordance with provincewide GHG monitoring and reporting requirements once the province established those. Shell would also be required to continue comparing emissions intensity to that indicated by the application and/or to industry-best practices and to describe measures that would be taken to reduce GHG emissions associated with the facility if necessary to achieve predicted performance levels and/or for continuous improvement.

AENV stated that Shell would be required to participate in the development of sectoral agreements applicable to oil sands processing plants, mines, and cogeneration plants. It also stated that Shell would be required to comply with any applicable GHG emissions limits or targets and any other provisions that may be established in a GHG sectoral agreement made applicable to the project.

14.6 Views of the Panel

The Panel notes that SO_2 emissions from the project would contribute only a 0.1 per cent increase in regional emissions. The Panel supports the proposed AENV condition to require Shell to collaborate with WBEA to support an ambient monitoring program that would validate predicted SO_2 and NO_x concentrations, as well as to participate in regional environmental management and monitoring initiatives to address acid deposition.

The Panel recognizes the concerns about NO_x emissions that would result from the project and the potential direct and indirect impacts these emissions would have on the environment on a project-specific and cumulative basis. However, the Panel notes that the conservative nature of the models used to predict ground-level concentrations of NO_x may overstate potential impacts of project emissions. The Panel expects Shell to meet its commitments to minimize NO_x emissions. The Panel also notes that an acidification management framework was tabled at the September 2003 CEMA meeting, and it expects Shell to meet its commitment to work within CEMA to implement this plan as regulators approve it.

The Panel supports AENV's intention to require Shell to demonstrate that all replacement mine vehicles would meet the latest vehicle emission standards and would be equipped with effective emission control technology.

The Panel believes that particulate matter emission and related precursor emissions should be controlled to the lowest practicable level through the use of the most appropriate pollution prevention and control technologies. The Panel accepts AENV's and Shell's position that the $PM_{2.5}$ modelling is conservative. The Panel further supports AENV including requirements in its approvals that Shell collaborate with WBEA on monitoring of $PM_{2.5}$ and PM precursors in the region, including Anzac and Conklin.

The Panel accepts Shell's commitment to use leading technologies to minimize GHG emissions and to develop a GHG management plan for the project. The Panel believes that the issue of GHGs can be dealt with through initiatives and policies developed at the federal and provincial levels. The Panel supports AENV in requiring appropriate GHG emissions and emissions intensity reporting. The Panel expects Shell to participate in the development of sectoral agreements that may be applicable to oil sands facilities and to abide by them.

The Panel believes that there is unlikely to be any significant adverse environmental effects to air quality as a result of the project, provided that the mitigation measures proposed are implemented.

15 CLIMATE CHANGE

15.1 Views of Shell

Shell stated that it had considered the effect of climate change in the EIA. Shell noted that it considered sensitivities of the project to climate parameters that were variable. Shell indicated that the project was designed for highly variable flows in the Athabasca River and it believed that changes to climate over the life of the project could be addressed through an adaptive management approach.

Shell stated that it believed it had incorporated the recommendations contained in *Canada's Working Draft Incorporating Climate Change Considerations in Environmental Assessment, General Guidance for Practitioners, January 8, 2002*. Shell believed that it had completed the requirements for an estimate of emissions, best practices in technology, commitment concerning reduction of emission, consideration of regulatory frameworks, and sensitivities to climate change parameters. Shell said that it was unable to use any climate change models because they had a high degree of uncertainty and variability, particularly for regional predictions.

Shell committed to consider the draft guidelines on climate change in future EIAs.

15.2 Views of MCFN

MCFN cautioned that climate change was a reality and would impact the long-term flows of the Athabasca River. The Fort McMurray region was predicted to increase in temperature by 5°C, becoming similar to the present temperatures of Lethbridge. Increased temperatures would have drying effects upon fens and bogs, with resultant decreases of flows to rivers. MCFN believed that climate change would make ecosystem shifts more probable, and that once ecosystems shifts happened, they would likely affect local climates and the hydrologic cycles. MCFN disagreed with Shell that climate change effects were adequately assessed for the region. MCFN requested that the Panel recommend to Canada and AENV that all future EIAs prepared in compliance with the requirements of CEAA and EPEA specifically consider the effects that climate change may have on the proposed project and cumulatively on the region. MCFN also recommended a water demand and supply study of the Athabasca River drainage basin that included climate change scenarios. MCFN further recommended that an independent agency, perhaps CEMA, complete a cumulative effects analysis that would predict the impacts on ecosystems function and services and would demonstrate whether the regional impact could be mitigated.

MCFN believed that Shell's EIA did not address climate change appropriately, but it stated that its concerns had been alleviated by Shell's commitment to do all it could to address climate change in the near future. MCFN stated that its concerns about climate change had been addressed through Shell's follow-up program to verify the accuracy of its predictions and the effectiveness of the proposed mitigation strategies.

15.3 Views of SCC

SCC believed that any projects in the Athabasca region should be required to follow *Canada's Working Draft Incorporating Climate Change Considerations in Environmental Assessment, General Guidance for Practitioners, January 8, 2002*. SCC argued that Shell had not considered the impact of climate change on the project in the EIA.

SCC stated that it was opposed to further development of the oil sands on the grounds of threats from climate change alone. SCC believed it was bad energy policy to permit projects that would bring fossil fuels on stream for decades when the country needed energy investment in other areas.

15.4 Views of Alberta

AENV stated that climate change and its consideration in EIAs was an emerging issue. AENV noted that the EIA terms of reference did not include climate change.

15.5 Views of the Panel

The Panel notes that the impact of climate change on the project was not part of the EIA terms of reference. When the federal government finalizes its guideline on climate change, the Panel expects all subsequent EIAs to follow those guidelines. The Panel agrees that Shell has considered climate change effects in a reasonable manner in its EIA. It agrees that climate change can be dealt with through an adaptive management approach.

The Panel believes that the impact of climate change on the project can be adaptively managed and therefore concludes that significant adverse effects are unlikely.

16 TERRESTRIAL RESOURCES

16.1 Wildlife

16.1.1 Views of Shell

Shell assessed local and regional effects of the project upon wildlife mortality, habitat loss and fragmentation, and barriers to wildlife movement. Shell used fourteen wildlife species as key indicator resources (KIRs). Shell predicted moderate environmental consequences at the local scale for some KIRs as a result of barriers to wildlife movement and changes to landscape composition and connectivity. Overall, Shell concluded that no significant adverse effects on wildlife would occur within the project area and no significant cumulative effects on wildlife would occur within the region.

Mitigation measures to reduce net effects included reduced surface disturbance and the use of existing rights-of-way. Shell designed the project with a 400 m wide corridor along the Muskeg River to maintain wildlife movements. To avoid critical wildlife periods, Shell stated that it would adopt seasonal timing restrictions in specific areas. Through CEMA, Shell would continue its participation in the development of a regional wildlife management plan. Shell committed to future wildlife monitoring for the project, using CEMA priority species and species of concern.

Shell stated that the conclusions made in the EIA concerning effects on wildlife would not be changed by future implementation of the Species at Risk Act. No species listed by the Committee on Endangered Wildlife in Canada (COSEWIC) had been located in Shell's LSA.

Shell stated that although different ecosystems would be found on the project site after reclamation, the land would have equivalent capability for most wildlife species. Regarding wildlife health, it did not expect any health concerns to arise from the project. Shell stated that it would implement mitigation measures such as deterrence to manage potential effects on migratory birds from the tailings disposal area. Shell stated that it was not necessary to monitor for toxic effects on migratory birds, since it did not predict adverse water quality effects. Shell responded to EC's recommendation for tissue monitoring of migratory birds by stating that it would consider the need for such monitoring. Shell suggested that the EC recommendation be amended to allow Shell to raise the bird monitoring issue within CEMA and/or WBEA.

16.1.2 Views of OSEC

OSEC was concerned that oil sands development would compromise the integrity of riparian wildlife habitat, wildlife movement corridors, and recreational use along the Muskeg River and Jackpine Creek. OSEC stated that the curved path of the Muskeg River and the boundary of the oil sands lease affected Shell's 400 m corridor next to the river, so that in some places the corridor would be only 100 m wide. OSEC did not believe that this was a sufficiently protective corridor.

16.1.3 Views of MCFN

The agreement between MCFN and Shell included ongoing consultation with MCFN about environmental effects of the project, including impacts on wildlife. Shell agreed with MCFN to undertake environmental monitoring to validate EIA predictions of the project and to review monitoring results and the effectiveness of mitigation measures with them annually. Shell agreed to seek input from MCFN in the design of project monitoring programs, including those dealing with wildlife populations and movement corridors.

16.1.4 Views of ACFN

Shell and ACFN reached an agreement to address concerns related to historic densities and movement of moose in the Muskeg River basin. ACFN and Shell agreed that Shell would consider participating in new organizations, such as a terrestrial monitoring group, that ACFN and a majority of stakeholders might propose.

16.1.5 Views of Fort McKay

The agreement between Shell and Fort McKay addressed key environmental issues, including wildlife species for subsistence hunting, trapper issues, and access management.

16.1.6 Views of SCC

SCC asserted that effects on wildlife would inevitability result from the project. These effects would extend beyond surface disturbance areas due to the diversion of water flows and would act in combination with other regional developments to substantially damage habitat. Other concerns were expressed about loss of biodiversity, nesting areas for migratory birds, and negative effects on wildlife from tailings, oil spills, and air emissions.

16.1.7 Views of Canada

EC was concerned that oil sands development in combination with other anthropogenic changes, such as forest harvesting, pipelines, and other infrastructure, would cause change to and loss of wildlife habitat. As a result, measurable impacts on wildlife, ecosystems, and ecological processes could occur. EC encouraged oil sands developers and all regulators to consider a cumulative and comprehensive approach to impact assessment, monitoring, and mitigation of impacts. EC recommended that interim environmental thresholds and objectives of CEMA be developed and implemented. EC stated that there was a need to assess the effects of each project on wildlife in a regional context and to assess those effects cumulatively with other developments in the region. EC asked that regulators consider the wildlife issues collectively.

EC stated that it was concerned about habitat loss and fragmentation in the boreal forest, as it was expected to lead to a decline of some songbird populations. To reduce disturbances to migratory birds and other wildlife during breeding, nesting, and fledging periods, EC recommended that vegetation clearing for the project not occur between April 1 and August 31.

EC stated that the project would result in the formation of sizeable EPLs to which migratory birds and other wildlife would be attracted. Therefore, EC recommended that Shell conduct long-term monitoring of potential contaminants from EPLs and air emissions and their effects on migratory birds.

EC questioned whether the indicator bird species selected by CEMA's Wildlife and Fish subgroup (WFG) were being monitored. Hence, EC recommended that Shell provide a detailed design and implementation schedule for its LSA for monitoring listed species and priority 1 and 2 indicator species identified by WFG. EC recommended that the information be provided prior to project construction.

In relation to the Species at Risk Act, EC stated that it had not identified any issues for the project. Nevertheless, if threatened or endangered species were discovered in the project area, it maintained that Shell would be expected to prevent the destruction of those species and their habitat.

16.1.8 Views of Alberta

ASRD and AENV agreed that Shell's wildlife mitigations were reasonable and considered a 400 m wide undisturbed corridor as a positive step toward maintaining wildlife habitat values and connectivity along the Muskeg River valley. Nevertheless, due to the increasing level of disturbance and the potential for long-term cumulative impacts on habitat connectivity, ASRD and AENV believed that natural dispersal patterns and seasonal range distributions of some wildlife species might be affected by the project. Consequently, ASRD and AENV requested the EUB to require Shell to undertake and lead a research and monitoring program to examine wildlife responses and effective setback distances for movement corridors in the oil sands area and to examine other potential innovative mitigation and reclamation measures.

16.1.9 Views of the Panel

The Panel recognizes that Shell's assessment of effects on wildlife assumed that the project effects occurred at one time and that predicted effects may be conservative. The fact that project effects on wildlife will likely be compounded during construction and operation of the project emphasizes the importance of successful implementation of Shell's mitigation measures and progressive reclamation. The Panel acknowledges that the EIA indicated moderate environmental effects for some species due to barriers to wildlife movement and for other species due to the removal of large-diameter trees in old growth forest. The Panel recommends that ASRD review with Shell opportunities to further mitigate losses of old growth forest attributed to the project.

The Panel agrees with ASRD and AENV that further research will be needed to evaluate wildlife corridors for effective movement of wildlife species. In establishing optimum features of corridors, such as size and distribution, the Panel believes an integrated approach involving multiple stakeholders and regulatory agencies would be beneficial. The Panel believes there are opportunities during scientific review of wildlife corridor effectiveness by Shell to consider other environmental benefits and mitigations that could contribute synergies or otherwise enhance the value of wildlife corridors. Ecosystem benefits are expected from maintaining limited areas of undisturbed native vegetation within oil sands leases for purposes of wildlife habitat, mitigating losses of old growth forest, biodiversity, reclamation, and watershed management.

The Panel recommends that ASRD and AENV require Shell to participate in a technical review of wildlife corridors that includes analysis of corridor width and effectiveness in facilitating wildlife movement and meets the regulatory needs of both agencies. Furthermore, the Panel recommends that ASRD and AENV review with Shell an action plan to maintain other islands or strips of undisturbed native vegetation on the Shell lease in association with wildlife corridors.

The Panel believes that avoiding vegetation clearing between April 1 and August 31 would mitigate impacts on migratory birds. The Panel expects that ASRD will adopt timing limitations consistent with other oil sands approvals. The Panel recommends that ASRD require Shell to develop a wildlife monitoring program for implementation prior to construction. The Panel expects the monitoring program to address federally and provincially listed species, as well as the priority 1 and 2 indicator species identified by CEMA.

The Panel expects that AENV and ASRD will review the recommendations of EC in view of work that may be implemented independently by Shell or cooperatively within CEMA. For example, the Panel understands that monitoring needs for the environmental effects of tailings and airshed contaminants upon migratory birds may be different in scope and application for regional and project scales. The Panel expects AENV, ASRD, and Shell to discuss appropriate indicators and time frames for Shell to validate its predictions of negligible effects on wildlife health, including that of migratory birds.

The Panel generally supports EC's recommendation for improved coordinated regional assessment and management of cumulative environmental effects, but believes that further review by EC, including consultation with DFO and AENV, on its feasibility and scope is necessary.

With the potential for listed species of the Species at Risk Act to be discovered in the project area and potential for changes to the COSEWIC species list, the Panel reminds Shell of the necessary vigilance required for ongoing compliance.

The Panel concludes that with the implementation of proposed mitigation measures and the recommendations of the Panel, significant adverse environmental effects on wildlife are unlikely.

16.2 Vegetation, Soils, Wetlands, and Forest Resources

16.2.1 Views of Shell

Shell compared the total disturbance of 8150 ha from the project to the entire area of Alberta's boreal forest natural region and concluded that the small change in total area was not significant. Shell stated that about 5919 ha would be disturbed at any one time during the project. Under baseline conditions, 88 per cent of Shell's regional study area (RSA) was undisturbed. Shell considered the boreal forest to be dynamic and subject to a range of naturally occurring ecosystem changes. Of the total disturbance attributed to the project, 3300 ha of peatlands would be replaced with upland soils and vegetation and 1600 ha would be replaced by open water. In its assessment of the local and regional vegetation resources, Shell compared land cover classes of KIRs that included riparian communities, economic forests, peatlands, old growth forest, rare plant potential, and traditional plant potential.

Shell stated that it ranked effects on vegetation, wetlands, and forest resources according to residual effects following progressive reclamation. Within the LSA, it assessed loss of wetlands and loss of areas containing high rare plant potential with high negative environmental effects. It predicted moderate beneficial environmental effects for terrestrial vegetation, economic forests, and traditional-use plants within the LSA after reclamation. Shell identified a number of project-specific mitigation measures, such as the use of existing disturbances, progressive reclamation and selective use of soil placement, conservation, and replacement of topsoil and organic matter.

Shell stated that it had completed a cumulative effects assessment within the RSA for the two vegetation KIRs, which predicted negative project impacts. It predicted loss of wetlands and loss of areas containing high rare plant potential to have moderate negative environmental effects. This was influenced in part by the inability to reclaim peatlands using current practices. Shell stated that it would continue its participation in the development of regional management systems within CEMA to address cumulative effects on vegetation. Shell acknowledged that some uncertainties existed surrounding the materials and methods of commercial-scale reclamation and committed to ongoing work within CONRAD to improve and develop reclamation techniques. Shell stated that it would monitor soil and vegetation re-establishment as part of its Conservation and Reclamation (C&R) Plan and closure activities.

Shell noted that CEMA's reclamation working group (RWG) had recently held a workshop to review the feasibility of restoring bogs and fens. Shell stated that it would support the restoration of bogs and fens if economically feasible methods were found.

Shell assessed the effects on soils in the LSA using KIRs that included permanent loss of soil units and mineral and organic soil units. It assessed project effects on both the quantity and capability of soil units. Shell assumed, on the basis of monitoring and research, that physical and land capability properties of reclaimed soils were similar to those of natural soils. Shell predicted the negative effects from the permanent loss of soil units to be of moderate consequence for the LSA. It predicted environmental effects of high consequence within the LSA for loss and alteration of organic soil units and for changes in forest capability.

Within the planned development case, Shell predicted that cumulative effects on soils would be negligible for all assessment criteria. Shell's primary mitigation for effects on terrain and soils was progressive reclamation intended to restore equivalent land capability. Shell proposed other project mitigation measures to reduce effects of erosion, compaction, salinity, and admixing. Shell committed to site-specific reclamation monitoring of soil and vegetation.

16.2.2 Views of OSEC

Shell addressed OSEC's concerns by agreeing to a wetlands monitoring program for the project. In addition, Shell agreed to examine opportunities to reduce drawdown of off-lease wetlands and also to work with OSEC to identify a wetland offset project and provide project funding to enhance wetland habitat for migratory birds of the boreal forest.

16.2.3 Views of MCFN

MCFN noted that the agreement with Shell included ongoing consultation with MCFN on vegetation and land use.

16.2.4 Views of ACFN

Shell and ACFN reached an agreement to address ACFN's concerns related to transplanting of plants important to ACFN.

16.2.5 Views of Fort McKay

Shell and Fort McKay reached an agreement that dealt with land disturbance, healing the land, medicinal plants, and access management.

16.2.6 Views of SCC

SCC stated that there would be major impacts on Canada's boreal forest from developments in northern Alberta. Effects could include reduction in the abundance of flora, fauna, and biodiversity, removal of forests, and acidification effects on forest fertility. SCC was concerned about the removal of 54 per cent of the old growth forest from the LSA. SCC challenged Shell's ability to re-establish wetlands. SCC asserted that peat wastage processes could result from hydrologic changes to wetlands and cause irreversible damage. SCC stated that re-establishment of wetlands as proposed by Shell would occur after 2030, and SCC wanted greater certainty for wetlands replacement in the near term.

16.2.7 Views of Canada

EC noted the importance of selecting environmental indicators suitable for detecting ecosystem changes at local, regional, and broader-range scales. In the context of pending implementation of CWS for particulates and ground-level ozone, EC recommended that stakeholders collectively identify suitable indicators for monitoring ecosystem responses to emissions.

16.2.8 Views of Alberta

Citing the report of the Oil Sands Mining End Land Use Committee (July 1998), AENV indicated that it could include approval conditions for Shell to achieve equivalent land capability and meet that committee's objectives for stable landforms with a diversity of forest and wetland ecosystems. AENV expected that soils and ecosystems would be returned to predisturbance capability to support large trees and other native vegetation.

AENV stated that long-term monitoring would be necessary to measure the effects of sulphur and nitrogen deposition on the environment. AENV stated that it might include approval conditions requiring Shell to support research to implement CEMA recommendations for an acidification management framework.

16.2.9 Views of the Panel

The Panel understands that effects of the project upon wetlands and rare plants are for the most part unavoidable and that the loss of some wetlands is likely irreversible. The Panel recognizes that there are uncertainties concerning the performance of reclamation materials for soils and vegetation.

The Panel believes that there are opportunities for Shell and other oil sands operators to evaluate the technical feasibility of engineered wetlands that resemble conditions of peatlands, bogs, and fens and to initiate demonstration research programs. The Panel recommends that ASRD and AENV identify this area of wetlands research as a priority for CEMA to address, and that they consider requiring Shell to support a program to facilitate wetlands restoration.

The Panel recommends that EC provide scientific expertise to CEMA working groups in the selection of appropriate indicators of terrestrial and aquatic ecosystems and in establishing effects-based monitoring systems for regional acid deposition.

The Panel supports AENV requiring Shell to address future implementation of CEMA's acidification management framework with additional research or monitoring of environmental receptors such as soils, vegetation, and water bodies.

The Panel concludes that with the implementation of mitigation measures and the recommendations of the Panel, significant adverse environmental effects on vegetation, soils, forests, and wetlands are unlikely.

16.3 Reclamation

16.3.1 Views of Shell

Shell stated that the project area would be fully reclaimed over time with phased reclamation activities throughout the operating life of the mine. Mining areas would be filled with residual tailings sand, and when the sand had consolidated to a firm landscape, it would be capped with overburden, covered in topsoil, recontoured, and revegetated. Shell stated that the goal was for complete reclamation by the end of the project.

Shell indicated that it defined disturbed lands as the first occurrence of clearing for any project-related activities. Shell stated that it had defined a reclaimed area as one in which the soil cover had been placed on the recontoured landforms and seedlings had been planted or seeds sown. Shell noted that its definition of reclamation would not meet Alberta's requirements for issuing a reclamation certificate.

Shell stated that the project's maximum footprint might change as detailed design progressed. While Shell acknowledged the EUB's desire to regulate a maximum level of project disturbance, Shell believed that it would be more appropriate to work on a series of reclamation milestones throughout the life of its project. It believed that this approach would meet the goal of promoting progressive reclamation. Shell noted that the set of reclamation milestones presented at the hearing might change after the project feasibility study was completed.

Shell stated that it was committed to continuing to conduct detailed reclamation monitoring and to participate in research to refine understanding of reclamation of wetlands and vegetation associated with CT areas. It supported research being done through CONRAD and the EPL subgroup of CEMA. Shell indicated that it would pursue an adaptive management approach to reclamation procedures that were based on research and on new best practices from RWG.

Shell recognized stakeholders' concerns that terrestrial landscapes and water bodies may not be reclaimed in the manner predicted and may not have productive end land uses. Shell believed that extensive ongoing research on tailings management and reclamation would lead to successful reclamation of the oil sands area.

16.3.2 Views of OSEC

OSEC believed that in the absence of an understanding of what the regional environmental thresholds might be, it would be prudent to minimize the amount of disturbance that was occurring. OSEC indicated that it had discussed the feasibility of a disturbance cap, and it agreed with Shell that simply having a cap for the amount of disturbance that a project could impose upon the landscape would do nothing to encourage an operator to minimize disturbance through progressive reclamation. OSEC agreed with Shell that a better approach would be the concept of reclamation milestones, in which an operator is constantly pursuing reclamation and minimizing overall disturbance.

16.3.3 Views of Alberta

ASRD stated that it supported progressive reclamation through either maximum disturbance limits or reclamation milestones. ASRD further indicated that there might be some merit to the milestone approach, since reclamation was not a continuous but a phased process.

ASRD stated that the biggest improvement to progressive reclamation would be to ensure that developers started reclamation immediately when land became available for reclamation, irrespective of budget constraints or other similar issues that might tend to defer reclamation efforts.

AENV stated that it might condition its approvals to ensure that reclamation resulted in a return to equivalent land capability, with integrated landscapes and ecosystems consistent with the report and recommendations of the Oil Sands Mining End Land Use Committee.

16.3.4 Views of the Panel

The Panel believes that reclamation planning and final landscape objectives are important considerations when determining whether an oil sands development is in the public interest.

The Panel is encouraged that Shell is implementing a progressive reclamation approach. The Panel understands progressive reclamation to mean that Shell will reclaim land as soon after disturbance as is reasonably possible and in a manner that is consistent with the closure plan.

The Panel is aware that although some overburden disposal areas have been reclaimed at the existing oil sands mines, none has been certified. Also the Panel notes that no tailings areas have been reclaimed. However, the Panel also notes that the nature of oil sands development inherently requires large areas of disturbance that may remain on the landscape over an extended period of time. The Panel notes that Shell has put a great deal of reliance on its progressive reclamation plans to mitigate the environmental impacts of the project.

In the absence of environmental thresholds or management objectives from CEMA, the Panel believes it is prudent to adopt a precautionary approach on the issue of reclamation. The Panel believes that, to the extent allowed by current technology, the oil sands industry should minimize the overall land disturbance and the maximum amount of land disturbed at any given time and that operators should strive to reclaim disturbed lands as soon as possible. Previously, the EUB has limited the amount of surface disturbance by establishing a maximum area of unreclaimed land within a project area. The Panel notes that Shell indicated that an appropriate number, if the EUB were to limit land disturbance in this case, would be 6309 ha, which is 78 per cent of the total proposed disturbance of 8150 ha.

The Panel acknowledges that Shell has suggested a reclamation milestone approach as an alternative to being regulated to a maximum disturbed area. The Panel believes that the milestone approach may have merit, but it notes that Shell has provided only a limited number of milestones and that it would be revising and finalizing this information after the feasibility study.

Although the Panel agrees with Shell's definitions of disturbed and reclaimed land, it believes that additional information would be needed to determine whether a maximum disturbance or a reclamation milestones approach is more appropriate. The Panel notes that the use of these approaches to regulate tailings management may also be considered in the EUB initiative to develop tailings performance criteria. The Panel recommends that AENV and ASRD consider whether additional performance criteria should be developed for progressive reclamation. These criteria could complement the proposed tailings management criteria described in Section 8 of this report.

The Panel notes that there are opportunities for Shell to revise and improve its reclamation plan as the project progresses and additional knowledge is gained through continued research and development on tailings.

16.4 End-Pit Lakes

16.4.1 Views of Shell

Shell stated that EPLs are permanent features of the project closure landscape. Shell supported the work of CONRAD and the CEMA EPL subgroup in researching the optimum design, operation, and mitigation measures for EPLs. Shell explained that the subgroup was completing literature reviews on EPLs and modelling for physical, biological, and chemical characteristics.

It stated that outside of its five-year plan, the subgroup planned a demonstration project through CONRAD.

Shell committed to validate EPL conclusions in the EIA through participation on the CEMA EPL subgroup and being part of the demonstration project. Shell stated that it would be 30 years until lake waters were discharged, which provided time to incorporate the results of ongoing reclamation research. Shell noted that other oil sands mines' EPLs would be discharging to the environment prior to the project EPL. Shell stated that it would use the knowledge gained from these closures in assessing the development of its EPL towards a productive ecosystem. Shell noted that Syncrude's Base Mine Lake was due to close in 2006, with first releases to the surroundings in about 2016. Shell suggested that this would be a large-scale, end-pit type lake that would be in place prior to the operation of Shell's EPL.

Shell stated that its EPL would have retention times to treat water quality for up to 18 years, and it believed that those waters could be released. Shell indicated that overall EPL water quality should be suitable to support aquatic ecosystems because all EPLs were predicted to be nontoxic when discharges to the environment commenced. Shell also noted that the western EPL would not have tailings at the bottom, which should assist Shell in meeting its water quality objectives more easily.

16.4.2 Views of Canada

DFO noted that there were no functioning examples of EPLs to verify Shell's EIA predictions. DFO stated that in the event that EPLs did not appear to be a viable option, it was imperative that alternative strategies be developed and implemented prior to mine closure.

DFO recommended that ongoing research into EPLs be continued and expanded to determine their ecological value over the long term. DFO further recommended that research be conducted or undertaken on mining and recovery options to reduce or eliminate the need for EPLs.

16.4.3 Views of Alberta

AENV recognized that groups such as RWG and the EPL subgroup were expected to address uncertainties regarding the viability of EPLs, their design and water quality. AENV understood that work plans were in place with appropriate schedules to develop a guidance document and theoretical designs for EPLs. AENV accepted Shell's predictions of functioning EPLs in the closure landscape.

AENV noted that it would be a number of years until the first EPLs were in place and stated that the complexity and uncertainty about their function made it critical that priority continue to be given to ongoing, comprehensive research. AENV stated that the pace of CEMA's work on the model development of EPLs and a guidance document was appropriate.

AENV stated that it expected greater attention to be paid to validation of models by early construction of a physical test case in the oil sands region. AENV indicated that it was not sure if the Syncrude Base Mine Lake would meet its expectations for validating EPL predictions. It explained that once the EPL subgroup completed its initial work, AENV would have a better understanding of what would constitute an appropriate demonstration. AENV stated that it might not be necessary to construct a full-scale EPL to test the physical components of the models being used. It understood Base Mine Lake to be a full test of a "water-capped" lake, but not necessarily of EPLs. AENV indicated that it might require Shell to provide a schedule that included the testing of EPL predictions and design features with a physical test case done in partnership with other oil sands companies.

AENV noted that any discharge from EPLs to natural surface waters would be required to meet Surface Water Quality Guidelines except where exceedances occurred naturally. AENV noted that the viability of EPLs as sustainable ecosystems in the closure drainage landscape for oil sands mines had yet to be conclusively substantiated. Uncertainty in EPL design, functionality, and water quality was identified under the Regional Sustainable Development Strategy (RSDS) as a significant issue. AENV stated that should EPLs not perform as expected, alternative water management measures could be required.

16.4.4 Views of the Panel

The Panel notes that EPLs have not been demonstrated within the oil sands industry. The Panel acknowledges that EPLs have been applied for and endorsed subject to successful demonstration in other oil sands projects and that testing is still proceeding to verify the feasibility of EPLs.

The Panel believes that an EPL demonstration is necessary. It notes that the EPL subgroup has identified that the next phase of its work would involve an EPL test program. The Panel supports AENV's intentions to require Shell to provide a research schedule that includes the testing of EPL predictions and design features with a physical test case done in partnership with other oil sands companies. The Panel believes that Shell, alone or in cooperation with other stakeholders, should identify a research and development plan to address the design, operation, and ecological viability of EPLs. The Panel expects sufficient work to verify EPL feasibility to be completed in the next 15 years. The Panel notes that this work may include a field demonstration or a full-scale test. The Panel recommends that AENV monitor EPL development and testing by Shell and other operators.

The Panel concludes that with the implementation of the mitigation measures and the recommendations of the Panel, significant adverse environmental effects associated with EPLs are unlikely.

17 MUSKEG RIVER INTEGRITY

17.1 Views of Shell

Shell stated that it considered the effects of the project on the Muskeg River basin water quantity and quality to be negligible, based on its proposed mitigation and water management plans. Shell determined that changes in water levels of Kearl Lake as a result of the project would be negligible. It predicted some water quality exceedances for some parameters in waters of Jackpine Creek, Muskeg Creek, and Muskeg River. Shell noted that predicted values exceeded the threshold value for fish tainting in the Muskeg River. However, because baseline conditions already exceeded the threshold, it deemed these effects to be negligible. See Figure 2 for a map of the Muskeg River drainage basin and main tributary channels.

Shell predicted negligible hydrological effects in its LSA and stated that it therefore did not require a regional assessment of hydrology. Shell also predicted negligible project effects for local water quality and stated that it therefore did not require a regional assessment of water quality. Shell noted that it did provide a planned development assessment for water quality for information purposes.

Shell completed a planned development assessment for effects on aquatic resources that were expected to overlap in time and space with the effects of other regional developments. It predicted a moderate magnitude for tainting of fish tissue in process-affected waters in Jackpine Creek in this case. Local impacts on affected aquatic habitats of the Muskeg River and its tributaries would be compensated for by construction of replacement habitat within a man-made lake.

Other assessments of cumulative effects on soils and vegetation in the RSA did not identify effects that would impair the sustainability of the drainage basin. Shell indicated that it was committed to establishing setbacks along the Muskeg River and Jackpine Creek to ensure the integrity of those streams and watershed. The project had also been designed to minimize surface disturbances and thereby provide a benefit for watershed integrity. Shell assumed in its analysis of the planned development case that other operators would adopt comparable mitigations so that major tributaries and the main channel of the Muskeg River would remain sustainable. Shell concluded that there were no unacceptable long-term environmental effects of the project.

Shell submitted a closure drainage plan to accompany its prefeasibility design of the project. Shell also submitted a Regional Development Update report that identified existing, approved, and future projects in the Muskeg River drainage basin. It included a layout of far future closure drainage features, such as diversion and drainage channels and reclaimed areas, EPLs, and retention ponds across an area of about five townships.

Shell believed that the MRWI subgroup would be identifying the ecological factors that could be at risk due to development and that the MRWI subgroup was developing a management system to ensure sustainability of the watershed. Shell indicated that it would provide leadership and proactively promote the work plan of this subgroup. Other regional initiatives, such as RAMP and the water working group (WWG), supported by Shell also contributed to the understanding and management of cumulative effects related to water resources and aquatic ecosystems. Shell stated that it would meet with regulators to discuss accelerating the work of the MRWI subgroup. Shell agreed in principle to support the management system and objectives for the Muskeg River drainage basin that CEMA might recommend for implementation by Alberta regulators.

17.2 Views of Fort McKay

In its agreement with Shell, Fort McKay requested that Shell address the environmental uncertainties of the impacts on undeveloped parts of the Muskeg River basin. Fort McKay requested that Shell conduct surficial groundwater monitoring and link it to rich fen and bog water level monitoring in order to develop benchmarks of acceptable levels of environmental change and to develop best management practices to minimize impacts in undeveloped parts of the Muskeg River basin.

In closing argument, Fort McKay requested that Shell be required to comply with the objectives and management systems produced by the MRWI subgroup. Fort McKay asked that management systems from the MRWI subgroup be in place prior to 2010, the anticipated opening of the project. Fort McKay asked Shell to proactively advance the work plan of the MRWI subgroup and meet with regulators to discuss the role of regulators in advancing CEMA's work.

17.3 Views of SCC

SCC questioned the accuracy of Shell's information concerning water flows of the Muskeg River, because it had not considered monthly flow variations and flow declines from climate change. This, it contended, would have a potential impact on river water management. SCC stated that it believed that it was necessary to complete a regional environmental assessment of all oil sands projects from the perspective of overall land-use planning.

17.4 Views of Canada

EC stated that there were potential risks of irreversible effects on the Muskeg River watershed from multiple oil sands projects during operations and reclamation. Therefore it recommended that Shell's water and sediment quality monitoring and dewatering monitoring and mitigation programs consider potential synergistic effects upon the Muskeg River and Jackpine Creek from adjacent projects.

DFO recommended that Shell continue its participation in the MRWI subgroup and adopt recommendations that might result.

17.5 Views of Alberta

Alberta stated that its review of the project was guided in part by two planning documents: the Fort McMurray-Athabasca Subregional Integrated Resource Plan (May 1996) and the RSDS (July 1999). In reference to CEMA, AENV understood that the MRWI subgroup was currently developing an environmental management system, with recommendations expected during 2005. AENV stated that it was prepared to take appropriate action if CEMA's work on an MRWI was delayed.

AENV acknowledged Shell's information that operational management of water and the final closure landscape from multiple oil sands projects in the Muskeg River drainage basin could have impacts on the functioning and integrity of the basin. AENV believed that a high degree of integration and cooperation supported by necessary regulatory requirements would be required among industrial users for water management, closure drainage, reclamation, and bitumen recovery to address this issue. AENV stated that it would regulate Shell and other operators by means of EPEA and Water Act approvals and by requiring their participation in CEMA groups, such as the RWG and MRWI subgroup.

17.6 Views of the Panel

The Panel commends Shell for its project design and mitigation measures to address stakeholder concerns related to water flows, water quality, and fish habitats of the Muskeg River basin. The Panel notes that AENV stated there was a need for monitoring programs to validate the EIA *predictions of negligible effects upon water quality, hydrology, and groundwater and to address* scientific uncertainties.

The Panel is aware of Shell's statements that its conservative approaches to assessment may in fact overestimate effects, and this would offset some scientific uncertainties in the assessment. The Panel supports the recommendations of EC that Shell complete additional baseline data and monitoring of water quality. It expects that AENV will consider requiring Shell to collect local and regional data, alone or in cooperation with RAMP, to validate Shell's water quality findings within the Muskeg River basin.

The Panel accepts that Shell has committed to setbacks along the Muskeg River and Jackpine Creek. The Panel recognizes that the potential for long-term effects to surface and groundwater flows entering the Muskeg River from Shell's mine pit may not be fully mitigated by a 100 m setback distance. The Panel recommends that AENV consider long-term environmental effects on the Muskeg River in the design of Shell's water monitoring programs.

CEMA has proposed work plans through the MRWI subgroup to develop management objectives and guidelines for the sustainability of the Muskeg River drainage basin. CEMA's work is expected to contribute a framework for cumulative environmental effects management within the drainage basin, with recommendations expected in 2005. The Panel believes that establishing guidelines and management systems for an area of intensive oil sands development such as the Muskeg River drainage basin should be given high priority so as to enable future development to proceed in an appropriate way. Consequently the Panel urges participants of the MRWI subgroup to accelerate its work so that it meets its objectives to ensure that an integrated drainage basin plan is developed by 2005.

The Panel notes that Shell's commitments are supportive of this goal. The Panel also notes that Shell's project schedule has sufficient lead time for adoption of new regulatory standards and guidelines prior to start-up. As a result, the Panel expects Shell to abide by the outcomes of the MRWI subgroup recommendations adopted by regulators. The Panel notes that AENV indicated that it is prepared to take necessary action should the MRWI subgroup fail to meet deadlines for the delivery of recommendations. The Panel believes that this step is necessary to increase regulatory certainty. Therefore, the Panel recommends that AENV develop management plans and objectives for the Muskeg River basin if MRWI subgroup timelines are not met.

18 COOPERATIVE REGIONAL DEVELOPMENT

18.1 Views of Shell

Shell supported the EUB expectation for a broad-based approach to developing all of the leases in the region in a way that will ensure that conservation and environmental objectives are considered and incorporated in the development plan. Shell stated that it was working with all leaseholders whose boundaries adjoined the project. Shell believed that cooperative regional development would allow the interests of one party to be considered by other parties as each developed its respective leases in the area. Shell believed that cooperative development would take into consideration resource conservation, environmental objectives, and public interest issues. Shell noted that it had cooperation agreements with Syncrude and ExxonMobil, which addressed minimization of lease boundary ore sterilization, joint surface water management plans, infrastructure use and routing, closure planning, and sharing of environmental data.

Shell provided a Regional Development Update (March 2003) that outlined opportunities for integration with the Syncrude Aurora South Development, provided the status of Shell's participation in regional initiatives, and provided a summary of the cumulative effects assessment for the project and other regional developments. Shell noted that discussions with Syncrude and ExxonMobil were ongoing. Shell provided examples of conceptual integration opportunities for the Jackpine Mine and the Syncrude Aurora South Development. Potential options for project integration would be subject to ratification by both companies and would also require EUB approval. Shell saw the integration options as "works in progress."

The Regional Development Update reviewed progress with Syncrude in matters of ore exchange along common lease boundaries, water management of flows to Jackpine Creek, Muskeg Creek, Kearl Lake, and the Muskeg River, infrastructure, and closure planning. Shell presented a conceptual closure drainage plan of the Aurora South and the Jackpine Mine developments, as well as options for surface water diversions during mine operations. It also provided a conceptual area development plan of surface disturbances from seven existing and future developments in the Muskeg River drainage basin.

Shell believed that the project would not compromise Syncrude's or Exxon/Mobil's ability to develop their leases. Nevertheless, Shell stated that it had designed the project as a stand-alone development that did not rely on plans of adjacent leaseholders, because adjacent projects were at various stages of development without detailed plans and were less certain than Shell's project.

Shell provided an integrated watershed strategy but noted that such planning was contingent on detailed development plans for developments that were not yet in place. Shell noted that the project had some flexibility to integrate future changes, such as Syncrude stream diversions. Hence, the Jackpine Mine would improve in terms of economic and environmental performance as the regional development process continued.

Shell stated that commingling of surface waters between developers from external tailings areas and the in-pit cells raised a number of practical and legal issues:

- allocation of legal liability for effluent streams of different chemical composition;
- allocation of risk and liability for management of a common tailings pond between and among parties;
- allocation of risk and liability for reclamation and the impact of the different chemical compositions of effluent streams on reclamation; and
- liability for abandonment and reclamation guarantee obligations.

Shell stated that legal liability for contaminants owned or under control of a party prohibited the use of a common tailings disposal area. Shell therefore believed that the commingling of waters, including process-affected waters, from adjacent oil sands facilities faced legal obstacles. However, Shell stated that upon project closure and reclamation, its release water could be commingled with other waters, provided that the released waters complied with AENV Water Quality Guidelines at lease boundaries.

Shell stated that it supported Muskeg River basin planning and integrated development plans to cooperatively achieve objectives of watershed management. Shell did not object to AENV's recommendation that the EUB require Shell to work with other operators and regulators to coordinate management of infrastructure development, reclamation activities, and the mine development. In Shell's view, it was already fulfilling this requirement.

18.2 Views of Syncrude

In closing argument, Syncrude stated that its Aurora project, adjacent to the proposed Jackpine Mine, was approved by the EUB. Therefore the EUB had already determined that the impacts of the Aurora project were acceptable and the project was in the public interest. Syncrude believed that cooperative regional development was a means of optimizing the performance of approved projects. Syncrude noted that it had approval conditions it was required to meet. Syncrude believed that the only parties that needed to be involved in ensuring that the conditions were followed were the approval holder (Syncrude) and the regulators. Syncrude believed that additional public input was not needed at this time, since the EUB would ensure that the public interest was protected as part of its process to ensure that approval conditions were met.

18.3 Views of Alberta

AENV stated that regional resource development required that the coordination of closure planning begin before development occurred. AENV stated that unnecessary environmental impacts might occur unless resource development and integration needs were well understood, with mitigation strategies determined at an early stage. AENV recommended that the Panel require Shell to work with other operators and regulators to coordinate management infrastructure, mine development, land reclamation, closures planning, and water management, as suggested in EUB *Decision 97-13: Application by Syncrude for the Aurora Mine* and *Decision 99-2: Shell Canada Limited Application to Construct and Operate an Oil Sands Mine in the Fort McMurray Area.*

AENV noted that in EPEA and Water Act approvals, it might require Shell to work with other operators to determine acceptable cross-lease boundary closure topography, watershed, wetlands, soil, and vegetation community. AENV also intended to support regional integration of development by requiring operators' continued participation in the RWG and MRWI subgroups.

18.4 Views of the Panel

The Panel acknowledges Shell's commitment to cooperative development and notes the obstacles Shell has faced in attempting to obtain project design information from other operators. The Panel agrees with Shell that cooperative development on lease boundaries, water management plans, infrastructure, closure drainage, and reclamation would improve Shell's project. In other sections of this report, the Panel notes that specific project components, such as the Canterra Road, Khahago surge pond, tailings disposal area location, PCA mapping, Muskeg Creek diversion, lease boundaries, and the compensation lake, would benefit from cooperative regional development and integration.

It appears to the Panel that the project was designed to contain all developments and disturbances to Lease 13 to the fullest extent possible. The Panel believes that such an approach is unlikely to provide the best overall project design or benefit for regional development. The Panel is encouraged by Shell's efforts to negotiate exchanges of portions of Lease 13 for portions of Syncrude's Aurora South lease in the interests of greater resource recovery at the common lease boundary. The Panel believes that there are similar opportunities to improve the project design, and reduce impacts from it by investigating the location of some facilities off Lease 13. For example, the Khahago Creek surge pond, tightly wedged between the tailings disposal area and the lease boundary, may better be located off lease. Additionally the Panel believes that there may be opportunities to optimize stream diversions east of Lease 13 if Shell, Syncrude, and ExxonMobil collaborate more closely.

Sometimes impediments stand in the way of an agreement being structured solely among the companies involved. Legal liability issues, surface rights, the loss of flexibility, and the prospect of higher initial costs are only some of the considerations that could affect a company's willingness or ability to strike agreements that are in the public interest. A properly focused regional initiative, with government participation, could provide a process that overcomes the obstacles preventing oil sands developers from addressing regional issues collectively. The Panel is uncertain whether the MRWI subgroup will address cooperative regional development and project integration issues. However, the Panel believes that the work of the MRWI subgroup, with the participation of multistakeholders, will contribute to the objectives of the EUB and other regulators for cooperative regional development.

The Panel believes that decisive actions to implement cooperative regional development are needed in the Muskeg River basin in order to optimize development in the interests of environmental management and resource recovery. Therefore, the Panel directs Shell to provide an annual report on regional development cooperation to the EUB, starting in 2005. The report should describe guiding principles and activities for cooperative development, opportunities and constraints of collaborative work among developers, specific time frames and implementation steps for all project phases to integrate them with other oil sands projects in the Muskeg River basin, and the means to evaluate outcomes. The Panel expects Syncrude and ExxonMobil to cooperate with Shell on this initiative.

Regarding Syncrude's comments that the only affected parties in respect to the Syncrude Aurora South development and compliance with approvals on it would be Syncrude and the regulators, the Panel believes that regional development opportunities may eventually result in significant changes to Syncrude's and Shell's projects that may require additional applications and amendments to EUB approvals.

19 MEASURES TO ENHANCE BENEFICIAL ENVIRONMENTAL EFFECTS

19.1 Views of Shell

Shell indicated that on a local scale, the environmental benefits of the project were related to new technologies, specifically caustic-free extraction, tailings thickeners, and lower-temperature extraction. On a larger regional scale, Shell had made a commitment to reduce its GHGs emissions from the project to a level less than that associated with imported oil. Shell also stated that additional monitoring and baseline environmental information would be collected as a result of the project. Shell had been working to improve models that apply to the oil sands region. In addition, because of Shell's Historic Resources Impact Assessment (HRIA), there was additional information on historic resources of the region.

Shell stated that the reclaimed site would have a land capability equivalent to that of the predisturbance area, but it would have higher capability for forestry. Shell would be increasing the area of class-2 and class-3 soil capability types. Shell also stated that some First Nations groups might view the compensation lake as a positive development, because there would be increased opportunities for fishing.

19.2 Views of the Panel

The Panel views the technologies that Shell would be using, CO_2 reduction, and the compensation lake as mitigation measures and not environmental benefits. With respect to reclamation activities that may improve land and soil capability, the Panel agrees that there may be an environmental benefit after reclamation is complete. However, the Panel concludes that there are unlikely to be any significant environmental benefits resulting from the project.

20 NEED FOR EIA FOLLOW-UP

20.1 Views of the Panel

Under CEAA, the Panel has a responsibility to conduct an assessment of the environmental effects of the project. In conducting this assessment, the Panel must ensure that all information required for its assessment is obtained and made available to the public.

The Panel has reviewed the EIA and the information brought forward during the hearings and concludes that it has the necessary information to conduct its assessment of the environmental effects of the project. It is satisfied that there is no additional information required to conclude that the project is not likely to cause significant adverse environmental effects, provided that mitigation measures and the recommendations of the Panel are implemented.

The Panel has considered the need for and requirements of follow-up in the environmental assessment of the project. This need has been discussed throughout this report in the appropriate sections. The specific areas of follow-up identified by the Panel include

- tailings management,
- effects on fish and fish habitat,
- effects on surface water quality and quantity,
- effects on groundwater,
- instream flow needs,
- effects on air emissions,
- effects on wildlife, and
- reclamation.

The Panel believes that the specific recommendations in this report should allow Shell to further develop the follow-up programs early in the planning stages of the project. The Panel expects Shell to consult and work with stakeholders who have a specific expertise or are interested in the development of the follow-up programs.

Specific recommendations in this report related to follow-up programs provide a mechanism to ensure that the programs are sufficiently detailed and scientifically rigorous. Shell's follow-up programs should

- contain sufficient baseline information,
- be quantitative in nature and have statistical power,
- include a description of the mitigation to be implemented,
- include detailed descriptions of the monitoring methods, timing, and duration of the study,
- contain reporting and success measurement criteria,
- be developed in consultation with stakeholders having specific expertise,
- ensure that consultation with the regulatory authorities has been carried out, and
- ensure that results are communicated to stakeholders.

21 REGIONAL ENVIRONMENTAL INITIATIVES

21.1 Views of Shell

Shell stated that it was an active member in regional environmental initiatives. It noted that the committees were involved in

- designing management systems for regional environmental issues,
- providing research information on new technologies, and
- collecting baseline, effects monitoring, and research information on aquatic, terrestrial, and air issues to aid in reducing uncertainties.

Shell stated that it was actively involved in CEMA, a registered not-for-profit nongovernment organization established in June 2000. CEMA's mandate was to make recommendations on how best to manage cumulative impacts and protect the environment in the region. Shell stated that CEMA was currently working on priority issues identified through RSDS issued by AENV in July 1999. Shell noted that CEMA consisted of groups working on NO_x/SO_x management, reclamation, TMAC, surface water, and sustainable ecosystem.

Shell also stated that it was actively involved in RAMP, which had been monitoring water and sediment quality, benthic invertebrate communities, and fish populations in the region since 1997. Shell noted that a climate and hydrology program was integrated into RAMP in 2000.

Shell stated that it participated in WBEA, a multistakeholder group with a mandate to conduct air quality, ecosystem, and human health effects monitoring in the region.

Shell stated that one of the reasons the CEMA working group had taken longer than envisioned to do its work was the time needed to establish relationships and trust. Also, CEMA was unique in how it had been addressing issues. Shell noted that CEMA had reorganized in the last few months to increase efficiency and effectiveness, and it believed these measures would help to rectify some concerns. Shell stated that it believed very strongly in CEMA and had a great deal of confidence that CEMA could meet its goals. Shell stated that it had the following suggestions for CEMA:

- CEMA should continue to focus on the issues of priority and those issues of priority should be integrated into a comprehensive work plan.
- All stakeholders should provide adequate resources to ensure that CEMA can meet its mandate.
- All stakeholders need to ensure a long-term commitment of personnel who have the appropriate skills and knowledge to sit on those committees to help the committee move forward.
- All stakeholders need to ensure that there will be continued accountability to meet the milestones at CEMA. Shell noted that CEMA had improved some of its accountability by ensuring that it had permanent staff and a new management committee.
- Industry members should be accountable to the working group.
- Working groups should put their efforts towards their main goal of very strong, comprehensive management systems; the pursuit of interim management objectives could distract them from their long-term goals.

Shell noted that it had eight people working on CEMA and that others needed to make the same kind of commitment to see CEMA succeed. Shell also noted that although a number of CEMA milestones were several years in the future, they were all well before the start of construction of the project.

Shell believed that RSDS and CEMA would continue to play a very important role in managing the cumulative environmental effects in RMWB. Shell believed that the region benefited from the multistakeholder forums and that the consensus-based decision-making process led to sustainable strategies that better addressed the cumulative needs of the RMWB. Shell believed that many of the regional cumulative environmental concerns raised, such as IFN, water quality, wildlife movement corridors, and acidification, were being addressed through the CEMA working groups. Shell further noted that if nonconsensus recommendation reports were produced by CEMA, AENV had the ultimate regulatory responsibility and authority to ensure that regional environmental management systems were developed and implemented.

Shell stated that it would support a condition within its approvals that mandated participation in CEMA and other regional monitoring programs.

21.2 Views of OSEC

OSEC stated that it was concerned about the scope, scale, and rate of regional environmental impacts from oil sands development in the absence of defined environmental limits. OSEC believed that the wisest course of action would be to determine environmental limits and allocate environmental capacity in an informed manner. OSEC also believed that the pace of proposed developments continued to outstrip the ability of CEMA to define environmental objectives and develop an environmental management system. It believed that for any consensus-based multistakeholder initiative, a regulatory backstop was required to ensure that the outcomes of the process were received in a timely manner.

OSEC noted that CASA, upon which CEMA had been modelled, had completed a number of challenging initiatives. It believed that a major reason for this was that AENV set clear end-dates, at which time it would make its decision. If a consensus recommendation was not available, AENV advised that it would make its decision based on available information from recommendations from the individual stakeholders. OSEC believed that this approach served as the impetus for advancing the work as efficiently as possible.

21.3 Views of MCFN

MCFN noted that CEMA work groups had a substantial level of commitment and range of skill level and experience. But it also noted that resources available for various tasks were not consistent. MCFN was concerned about the lack of products from CEMA but stated that it would continue to participate in CEMA so long as CEMA was making progress towards its goals.

21.4 Views of WBFN

WBFN believed that CEMA had good intentions but appeared overloaded. WBFN believed that CEMA should be given additional funds to speed up its work.

21.5 Views of ACFN

In closing argument, ACFN noted that Shell had agreed to limit its withdrawal from the Athabasca River in accordance with any CEMA IFN recommendations. Therefore it was very important to ACFN that an objective was set for IFN as soon as practicable. ACFN was committed to working and solving problems at the CEMA table. ACFN stated that its support and commitment to CEMA were related to CEMA's ability to bring forward meaningful results in a timely manner. ACFN noted that the development of the Muskeg River basin management system was also important.

21.6 Views of Fort McKay

In closing argument, Fort McKay stated that it was a strong supporter and participant in the multistakeholder organizations and would continue to be so as long as they were making progress in meeting their mandates and were not impeded by funding shortfalls. Fort McKay stated that it had significant reservations about CEMA's ability to fulfill its mandate based on recent restrictions on CEMA funding imposed by industry participants. It believed that the pace of granting approvals by regulators had outstripped the ability of CEMA to develop and recommend appropriate regional thresholds for environmental protection. Fort McKay recommended that the Panel endorse timelines for CEMA to develop and recommend an introductory set of environmental management objectives or management systems for NO_x, sulphur oxides (SO_x), IFN, and water quality for the Athabasca River, MRWI, fish tainting, and conservation of terrestrial resources.

21.7 Views of SCC

SCC stated that the CEMA effort was quite laudable and progressive, but it was concerned that CEMA had not delivered on key information pieces, such as IFN. It believed that new developments should not be approved in advance of knowing some of those key pieces of information.

21.8 Views of Canada

EC acknowledged that regional environmental thresholds and objectives were not yet in place. It recommended the development and implementation of interim environmental guidelines by CEMA working groups. This would be consistent with CEMA's own terms of reference and the precautionary principle. EC noted that Shell did not support the pursuit of interim thresholds and objectives. EC further explained that the pursuit of interim thresholds and objectives was not intended to replace or distract from the ongoing CEMA activities. EC noted that a better description of its recommendation would be a staged or phased approach to thresholds similar to what was presented to CEMA as the acidification management plan.

EC stated that it was committed to help prioritize CEMA work and to review timelines. EC stated that it would work towards making sure CEMA reached its timelines.

21.9 Views of Alberta

AENV noted that RSDS was being implemented in partnership with CEMA. Based on identification of priority issues, CEMA working groups were developing recommendations for regional environmental management to be approved by all CEMA members. Recommendations approved by CEMA would be provided to AENV for consideration and, if approved, for implementation.

AENV noted a number of CEMA accomplishments:

- In August 2002, CEMA forwarded to regulators consensus recommendations for managing trace metals in the RMWB, which AENV reviewed and endorsed. These recommendations included a goal, a management objective and actions, research, monitoring activities, and an evaluation period.
- In July 2003, CEMA industry members voluntarily agreed to adopt three management tools to help minimize land disturbance related to industrial development and exploration.
- As of August 2003, CEMA had completed over 28 technical reports, with over 22 other reports in progress, supporting the development of environmental management systems.

AENV stated that it might include conditions in the EPEA or Water Act approvals that required Shell to

- participate in the activities of CEMA,
- support an ongoing research program to implement CEMA recommendations for an acidification management framework,
- support an ongoing research program to develop CEMA recommendations for developing an HFN assessment for the lower Athabasca River,

- support an ongoing research program to develop CEMA recommendations for sustainability of the Muskeg River basin,
- support an ongoing research program to develop CEMA recommendations for EPLs, and
- submit plans demonstrating how the project could be adapted to meet future regional environmental objectives and environmental management systems.

AENV noted that enhanced financial commitment by stakeholders to implement on-the-ground research would be required for successful completion of the deliverables expected under RSDS.

21.10 Views of the Panel

The Panel notes that Shell has identified the importance of regional initiatives to address adverse environmental effects of the project. It has also relied on monitoring, adaptive management, and reclamation activities to mitigate against these effects. In other sections of this report, possible additional monitoring activities are identified for regional initiatives such as RAMP and WBEA.

With regard to CEMA, the Panel believes that CEMA's work is important and that the results will assist the EUB in meeting its regulatory mandate to ensure that energy developments are carried out in an orderly and efficient manner that protects the public interest. The Panel understands that there is good support in general for CEMA but widespread concern about delays in delivery of environmental management objectives and plans. The Panel believes that in light of the delays in producing management objectives and plans, it would be useful to all stakeholders if AENV and ASRD were to review the progress of CEMA and update their expectations of RSDS.

The Panel acknowledges the broad spectrum of regional environmental issues that CEMA is expected to manage as a consensus-based multistakeholder organization. CEMA's diverse membership of industry, First Nations, local aboriginal groups, regulatory agencies, nongovernmental organizations, and other stakeholders presents its own challenges respecting consensus-based decision-making, financial resources, and priority setting.

The Panel heard concerns relating to CEMA's funding and its ability to obtain expert consultants that may have hampered CEMA work process. In addition, the Panel heard that CEMA's recent restructuring and reprioritization would improve its ability to meet critical timelines. The Panel commends CEMA for its efforts to streamline and integrate its goals and organizational structure. Nevertheless, the Panel has concerns that CEMA's effectiveness may also be influenced by the volume and complexity of its work, multiple priorities of stakeholders and funding mechanisms that may not keep pace with CEMA's increased workload. The Panel believes that restructuring and reprioritization are the first steps to ensuring that CEMA meets its goals and the expectations others have of it.

The Panel believes that it is important that CEMA's level of funding and participation is sufficient in light of the increasing level of regional development and capital spending now occurring and planned for the oil sands region. The Panel urges all CEMA participants to re-evaluate their financial support and staff resourcing allocated to CEMA and ensure that they are comparable to the amount of reliance it has put on CEMA to manage cumulative environmental effects in the region. The Panel also urges all CEMA participants to ensure that their staff are accountable for the completion of CEMA deliverables. CEMA participants may want to consider dedicating full-time staff to this initiative, as opposed to the part-time approach. In addition, the Panel supports EC, DFO, AENV, and ASRD in reviewing and optimizing their financial and human resourcing of CEMA to produce meaningful results in an earlier timeframe. The EUB will also examine its financial and human resourcing to the CEMA process and make changes as needed.

The Panel notes that as part of the restructuring initiative, CEMA would provide project managers for the working groups. The Panel believes that assignment of technical experts to the working groups to facilitate dealing with complex scientific issues should also be considered.

The Panel has serious concerns about delays in the issuance of recommendations and the ability of CEMA to meet the proposed timelines. The Panel heard evidence that AENV is prepared to take action should CEMA not meet deadlines for delivery of recommendations for environmental management systems to regulators for approval. The Panel believes this step is necessary to increase regulatory certainty. Therefore, in addition to the recommendations on IFN and MRWI, the Panel recommends that AENV and ASRD consider developing management plans or objectives respecting other environmental issues if CEMA timelines are not met.

The Panel notes that Shell has committed to participate in CEMA and would accept participation as a condition of approval. The Panel supports AENV's intention to condition its approval. It recommends that DFO consider conditioning its approval to require Shell to participate in CEMA.

The Panel notes that recommendations from the MRWI, IFN, and wildlife corridor subgroups are not yet available. As a result, the Panel expects Shell to abide by the outcomes of these working groups and the other regional environmental management initiatives once adopted by the regulators. When CEMA or other regional initiatives have produced substantive results or AENV has acted within its mandate and set management objectives, the EUB will consider the need to review Shell's and other oil sands approvals.

22 SOCIAL AND ECONOMIC IMPACTS

22.1 Macro-Economic Impacts

22.1.1 Views of Shell

Shell stated that the project would bring substantial benefits to Alberta and Canada. It indicated that the overall investment for the project was $2 billion and suggested that the project would be the catalyst for additional investments in pipeline infrastructure and further upgrading facilities in Alberta. Shell estimated that about 10 per cent of the project investment would likely accrue to RMWB residents and companies. It estimated that another 40 per cent would accrue to the rest of Alberta and roughly 10 per cent would accrue to the rest of Canada.

Shell projected that the project would require a peak construction workforce of 2500 and another 970 operations jobs. Shell committed that jobs created by the project would be filled by local residents whenever possible, but strictly on a merit basis.

Shell projected annual operating costs to be about $450 million, of which Shell estimated that 70 per cent would accrue to Alberta workers and companies, with many originating in the Wood Buffalo area.

Shell estimated that the project would pay almost $2 billion in taxes and royalties to the federal and provincial governments by 2036. It estimated property tax payments to the RMWB at roughly $3 million per year, or $83 million over the life of the project.

Shell also indicated that the Wood Buffalo region had already benefited through company donations of over $1.5 million since Shell began its consultation effort in 1996. According to Shell, this included leading donations to the new Technology Centre at Keyano College, to the CT Scanner and medical outreach vehicles at the hospital, and to the redevelopment of the Oil Sands Discovery Centre.

22.1.2 Views of the Panel

The Panel acknowledges the economic benefits to the region, the province, and Canada associated with the project and notes the letter of support for the project from the RMWB. While the taxes and royalties generated by the project will be offset to some degree by the need for government to invest in new infrastructure and expanded public services, the Panel believes that the net benefit from taxes and royalties to Alberta and to Canada will be significant.

The Panel also acknowledges Shell's efforts to support the advancement of education and training locally and its efforts to support the growth and development of local business. The Panel encourages companies to take an active role in supporting initiatives aimed at ensuring that the economic benefits are made available to the broadest possible number of local residents and businesses wanting to participate in the economic opportunities created.

22.2 Public Infrastructure/Services

22.2.1 Views of Shell

Shell acknowledged that the project would contribute to a number of broad social and economic impacts in the region. The impacts identified by Shell related to employment, housing, education, health and emergency services, social services, and transportation infrastructure. Shell suggested that many of these impacts were pre-existing, as a result of previous oil sands development activity in the region, but also recognized that the project would contribute to the cumulative impacts from oil sands developments. Shell indicated it had been working with the Northern Lights Regional Health Authority (RHA), RMWB, and RIWG, as well as the provincial government and other oil sands developers to understand and find solutions to socioeconomic impacts that were cumulative in nature.

Shell stated that it was committed to taking a proactive role in finding solutions to regional socioeconomic issues. However, Shell was also clear on what it perceived its role to be with respect to socioeconomic matters. Specifically, Shell stated that it would

- take direct responsibility for those areas directly under its control,
- facilitate and advocate in areas not under its control, and

- where appropriate, provide resources for identifying and managing impacts.

Shell indicated that it would continue to participate in the Athabasca Resource Development Facilitators Committee to lobby at a senior level within government for resolution of the region's socioeconomic and health care issues.

22.2.2 Views of OSEC

OSEC expressed concern about the cumulative impacts to municipal infrastructure, traffic, health, housing, retail, and nonprofit agencies. OSEC believed that the socioeconomic concerns of Fort McMurray and area residents were not being addressed in a timely or adequate manner to keep pace with the rate of industrial development in the Wood Buffalo region.

OSEC argued that RIWG was not consensus based, did not include the participation of all stakeholders, and approached socioeconomic issues on an ad-hoc basis. OSEC suggested that the development of a new consensus-based multistakeholder group was needed. It believed that this new group should be tasked with identifying and addressing socioeconomic issues and developing recommendations to the appropriate government authorities. OSEC believed that this group could provide a new approach to addressing socioeconomic issues by bringing together a greater understanding of the issues and in turn could be more effective in designing and implementing effective and comprehensive solutions that met the needs of the community.

OSEC noted that its agreement with Shell contained a commitment by Shell to champion the development of an affordable housing subcommittee through RIWG and to provide staff time and funding in support of the subcommittee. In addition, OSEC made reference to a new social indicators subcommittee that was recently formed by RIWG to gather better quantifiable data on social impacts. OSEC was unable to provide additional details about this committee, other than to indicate that the subcommittee was intended to have a monitoring role.

22.2.3 Views of WBFN

WBFN indicated that while oil sands development brought jobs, it also brought increased social problems as a result of alcohol and drug use. WBFN believed that the lifestyle of the aboriginal people living in Fort McMurray had changed drastically over the years due to the rising cost of living and the high cost of housing. WBFN spoke of the need to address the homelessness of some WBFN members.

22.2.4 Views of MCFN

MCFN indicated that its agreement with Shell contained commitments and a process by which Shell would deal with key socioeconomic concerns raised by the MCFN.

22.2.5 Views of ACFN

The ACFN agreement with Shell provided for the establishment a long-term relationship to address socioeconomic issues of ACFN and its members.

22.2.6 Views of Fort McKay

Fort McKay's agreement with Shell dealt with its socioeconomic concerns.

22.2.7 Views of FMMSA

The Fort McMurray Medical Staff Association (FMMSA) stated that it was very concerned about the effects of further oil sands development on an already overstretched health care system and expressed concern for Shell employees of the project who would face limited access to family doctors and to the health care system in general.

FMMSA described the Fort McMurray region as the most underserviced area in Canada in terms of family practice. It also indicated that the region did not have orthopaedic services, a magnetic resonance imager (MRI), or a variety of other diagnostic and visiting specialist services that were needed. FMMSA indicated that there were shortages in air medivac services and that improvements were needed for the rapid response emergency medical system. It described a hospital emergency room (ER) that was routinely operated at capacity and ER facilities that made it physically impossible to increase capacity by having two ER physicians working side by side.

FMMSA asserted that health care was underfunded in the region. Specifically, FMMSA argued that the funding formula was not capable of taking into account the unique situation in the Wood Buffalo region and therefore the health region was being penalized in terms of funding. FMMSA pointed to the rapid population growth that had occurred to meet the labour demands of oil sands developments, the large work camp population and shadow population in the region, the low incidence of elderly remaining in the region due to the high cost of living, and to medical staff recruitment challenges, given the remoteness and the high cost to live and operate a business in Fort McMurray.

FMMSA stated that the demands on the health care system had grown tremendously in recent years and believed that unless the health care system was able to keep pace, there would be an increasing problem with access to health care in Fort McMurray. FMMSA cited a study (referred to as the Cuff Report) undertaken by the RHA and AHW to examine health care funding in the region, but stated that it had been unable to obtain any published results. It also stated that it was aware of a provincial interdepartmental committee that was looking at the infrastructure needs (including health) of the region and that it was also aware of a survey of camp workers and the social indicators subcommittee of RIWG. FMMSA indicated that it had not been able to obtain any of the results from these initiatives and had not been consulted on any of them.

FMMSA requested that the Panel appeal to the Minister for AHW and to the Premier of Alberta for improved health care funding for the region. FMMSA also requested that the Panel recommend to government that a standing policy committee be established to address the unique health care funding needs of rapid-growth areas or, alternatively, recommend that an Order in Council be passed to deal with the disparity and underfunding of health care in remote regions experiencing rapid growth. FMMSA believed that better oversight and monitoring were needed by government to set minimal standards to ensure fair and equitable access to health care for people living in the Wood Buffalo region.

FMMSA acknowledged that Shell could not resolve issues related to health care on its own and could not make up for the lack of RHA funding. However, it did suggest a number of ways Shell could help reduce the strain on the health care system, including by advocating for more health care funding in the region, providing enhanced on-site health services to help relieve pressures on the emergency room (however, it noted that this might also result in increased pressure on the labs and diagnostics at the hospital), emphasizing prevention, maintaining its safety track record, and considering on-site rapid helicopter evacuation available to the whole community so that everybody benefited both during and after work hours.

22.2.8 Views of Alberta

AHW addressed the concerns raised with respect to health services and affordable housing in Fort McMurray. It was the position of AHW that the people served by the RHA had equitable access to first-rate services both in the region and throughout the Capital Health region. It further stated that the issues raised by FMMSA with respect to health services were well known and were much discussed between the RHA and AHW. It emphasized that there were mechanisms in place to deal with issues of health care in the region, and it stated that a world-class funding formula was in place to resource the health authorities.

AHW indicated that it had not raised the issue that lack of affordable housing in Fort McMurray could contribute to adverse human health effects because it was comfortable with the progress made to address affordable housing. It also stated that it took comfort in knowing that the issue of affordable housing was now being looked at within the existing regional groups that addressed socioeconomic issues.

22.2.9 Views of the Panel

The Panel acknowledges that the evidence provided by Shell and interveners indicates that certain public services and infrastructure are struggling to keep pace with the rate of industrial development and population increase in the region. The Panel appreciates that industrial growth does bring about change and it recognizes that extensive industrial development can strain public services and infrastructure. The Panel believes that the benefit to oil sands companies and to the broad public interest derived from a mobile labour force moving into the region to construct a major oil sands project should not come at the expense of an adequate level of public services to long-term Wood Buffalo residents. The Panel can foresee that without proper attention to emerging social and medical issues and without allowing for lead times to invest in new staff, services and facilities, the potential exists for some public infrastructure and services to be severely impacted.

To determine the significance of socioeconomic impacts, the Panel looks to the evidence presented for indications that the appropriate authorities are effectively managing the impacts. The Panel believes that how well a community manages change will ultimately determine the capacity for public services and infrastructure to respond to increasing demands. The Panel did hear evidence suggesting that the appropriate authorities are responding. Reference was made to the work being done by RIWG and the Oil Sands Development Facilitation Committee. There were also references to a survey of camp workers by RIWG, to the Cuff Report, and to a provincial interdepartmental committee reviewing the capital and program delivery needs in the Wood Buffalo region. The Panel also notes the evidence provided by AHW that existing mechanisms are in place to deal with issues relating to health care in the region. Yet, the Panel was given little information beyond assurances that the social impacts are being managed. There was no evidence presented to indicate that the subcommittees of RIWG are effective in achieving the desired results, and information on the survey of camp workers and the Cuff Report or the work of the interdepartmental committee was either not available or not released to the public.

In previous EUB proceedings on major energy facilities in the Wood Buffalo region, the EUB has expressed the view that the responsible government agencies are aware of the impacts and are responding to them. The Panel believes that this is still the case. However, given the expected growth pressures from oil sands developments in the Wood Buffalo region, the Panel perceives there is a need for a reliable source of information on the social and economic challenges (and opportunities) facing the region. The Panel believes that the residents of Wood Buffalo should be provided with information that gives them confidence that adaptive management processes are in place and succeeding with respect to socioeconomic and health matters. A process is needed that provides a coordinated and effective channel through which regional and cumulative socioeconomic impacts can be addressed in a meaningful and demonstrable way. The Panel expects adequate monitoring and verifying of predictions to take place with respect to socioeconomic and health issues and expects this information to be communicated to the residents of Wood Buffalo.

The Panel believes that there is a need for government and the multistakeholder committees addressing socioeconomic issues to better communicate the outcomes (successes and failures) of their work to the residents of Wood Buffalo. The Panel suggests that a formal, coordinated annual compilation of the activities and outcomes from the existing committees and relevant government departments might prove useful. This type of annual progress statement on socioeconomic issues would be reported publicly to provide residents with benchmarks to assess the state of the region and to give them confidence that something is being done. Annual reporting on socioeconomic issues would also serve to provide guidance and focus for the responsible authorities and elected officials working to bring about positive change in the region.

The Panel is encouraged by the efforts of RIWG to establish a social indicators subcommittee. Although no specifics were given on the role of the subcommittee, the Panel believes that establishing indicators and measuring progress is a powerful catalyst for strategic thinking and collaborative action on socioeconomic issues.

While the Panel does recognize that governments and multistakeholder committees are tackling regional socioeconomic issues, it believes better coordination and communication could further enhance these efforts. Some of the interveners suggested that a new consensus-based multistakeholder committee was needed to address socioeconomic issues. The Panel agrees in principle that the process for addressing socioeconomic issues should involve all affected stakeholders, but it does not take a position on how this can best be accomplished (whether through a new committee or accommodated within the existing committees).

The Panel recommends that all levels of government take steps to further enhance the level of planning, communication, and response around socioeconomic and health matters in the Wood Buffalo region. The Panel believes that taking action now on social and health issues will further enhance the region as a place for businesses, workers, and their families to locate and, in turn, will increase the competitiveness of the region to attract and sustain oil sands investment.

Providing a timely and reliable source of information upon which strategic decisions can be made is especially important to this area, given the expected growth pressures it will continue to experience.

23 TRADITIONAL LAND USE

23.1 Views of Shell

Shell stated that it had worked with First Nations, Metis, and other aboriginal groups in the region to integrate traditional environmental knowledge (TEK) into the project EIA and into the regional environmental monitoring and management systems. Shell indicated that TEK was obtained from interviews with nine trappers and traditional land-use studies prepared for other applications, for Fort McKay, and for Lease 13, which was integrated throughout the EIA. In particular, TEK was included in generating the baseline information on resources and resource use and in discussions on ongoing effects of development on aboriginal lifestyles and fish.

Shell stated that First Nations trappers, who would be directly affected by the project, were consulted early in the process and had issues dealt with, and their involvement helped to determine the preferred option for stream diversions.

Shell indicated that its consultation with traditional land users identified a number of key concerns; as well, Shell believed that the various environmental and socioeconomic agreements it had with First Nations and Metis in the region dealt specifically with their unique concerns.

23.2 Views of MCFN

MCFN explained that the hunting, gathering, and trapping activities of its members took them long distances away from their communities, including to traplines they had in the area of Fort McKay. MCFN stressed that one of the most important issues for its members was water, both in terms of quality and quantity in the river system. MCFN explained that elders and members of MCFN used the water to access their traditional lands where they gathered, hunted, fished, and trapped. MCFN stated that it had witnessed a big change in the water system, especially in the Peace Athabasca Delta, and that changes in water quantity were making it harder for them to access their traditional lands and travel to Fort McMurray.

MCFN indicated that oil sands developments should not proceed at the expense of water, land, or the animals that were still hunted and trapped for subsistence by a number of MCFN members.

MCFN acknowledged that Shell committed to provide it with funding for a traditional land-use study.

23.3 Views of WBFN

WBFN expressed interest in participating in traditional land-use studies to help protect and preserve historic sites and gravesites that had relevance to WBFN members.

23.4 Views of ACFN

In closing argument, ACFN stated that water was at the heart of its concerns, as ACFN members had traditionally relied heavily on the Athabasca River for drinking and fishing and as a transportation artery to access lands for hunting and trapping. ACFN stated that the agreement it had with Shell helped to ensure that any adverse impacts of the project were minimized and that the land was safely and fully reclaimed. The agreement also addressed opportunities for ACFN to benefit from the project, which, in its view, would help to ensure the future survival and prosperity of ACFN.

23.5 Views of Fort McKay

In closing argument, Fort McKay stated that the traditional lands of the First Nation and Metis members lay at the heart of oil sands development. Fort McKay indicated that the agreement it signed with Shell was critical to Fort McKay's belief that the adverse impacts of the project would be managed and mitigated in a manner acceptable to the elders and other members of the community of Fort McKay.

23.6 Views of the Panel

The Panel believes that the assessment of traditional land use, as well as the integration of traditional knowledge, has been adequately dealt with by Shell. The Panel notes that the various agreements indicate that Shell is actively working with First Nations and Metis in the region. The Panel also notes that within these agreements, Shell has made commitments to address environmental concerns and to support and promote traditional practices.

The Panel concludes that given Shell's commitments to work with First Nations, Metis, and other aboriginal groups in the area and to take steps to address their concerns, it is unlikely that traditional land use will be significantly affected as a result of the project.

24 HUMAN HEALTH

24.1 Views of Shell

Shell stated that air and water releases from the project were assessed for potential effects on human health in accordance with EPEA, HC, and World Health Organization (WHO) guidelines for health risk assessment. Shell indicated that the assessment predicted no negative health effects for most chemicals of potential concern. In instances where the predicted exposure ratio was greater than the benchmark value of 1.0, Shell stated that given the conservatism built into Shell's modelling, it was unlikely that those exposures would have any health impacts. Shell noted that AHW commented that Shell used an acceptable methodology and concurred with Shell's assessment and conclusions.

Shell noted that MCFN had expressed concerns about the health of its members living downstream of the oil sands plants. In recognition of these concerns, Shell agreed to participate in a baseline health study of the Fort Chipewyan population, as outlined in its agreement with MCFN.

24.2 Views of MCFN

MCFN stated that it had concerns about its members' health. MCFN read from a letter by Dr. J. O'Connor, a family physician in Fort McMurray, with a specific focus on the aboriginal communities surrounding Fort McMurray. The letter expressed concern about an increasing incidence of disease and pathology over the past few years in Fort Chipewyan that was unrelated to lifestyle and suggested there were questions that needed to be answered regarding the health of the residents in this area. MCFN indicated that it shared Dr. O'Connor's concerns.

MCFN's agreement with Shell included a commitment by Shell to contribute funding to a baseline health study of the Fort Chipewyan population, provided that the study was conducted independently and with appropriate scientific rigour and provided that other oil sands developers and/or governments agreed to participate in the funding of the study.

24.3 Views of FMMSA

FMMSA indicated that it was concerned about the high incidence of serious illness in First Nations, Metis, and other aboriginal people. FMMSA expressed a need for more data with respect to community health and recommended that a long-term study of health for the region's population be established. FMMSA suggested that a single snapshot study of community health would be easily dismissed.

24.4 Views of Canada

HC provided background information on WHO and CWS for various air emissions, but it did not comment on the health risk assessment completed for the project.

HC indicated that it had an Environmental Health Officer working in the area who was actively involved with WBEA. HC stated that it supported the efforts of WBEA to implement an ongoing monitoring program and indicated it would participate and contribute money to the program.

24.5 Views of Alberta

AHW stated that an interdepartmental human health review team (lead by Health Surveillance and including representation from HC) reviewed the project EIA. AHW believed that Shell had used an acceptable methodology for its human health risk assessment and the conclusions drawn from the assessment were reasonable. AHW noted that there were predicted air quality guideline exceedances, which, it suggested, were likely the result of highly conservative modelling methods. AHW indicated that validation of the predictions made by Shell would be a logical next step to further address the predicted exceedances. AHW indicated that it would collaborate with AENV to determine what conditions of an EPEA approval might be appropriate to address this issue.

AHW also pointed to the results of the Alberta Oil Sands Community Exposure and Health Effects Assessment Program conducted by AHW and other stakeholders and released in May 2000. AHW indicated that the analysis concluded that air emissions from industrial development produced no measurable negative impact on overall health and no significant differences were found between the population in Fort McMurray and the population of a control group in Lethbridge. AHW indicated that the Fort McKay First Nation also commissioned a Community Exposure and Health Effects Assessment Program for the community of Fort McKay. However, it stated that the findings of this study had not been released to the public.

AHW stated that one of the recommendations made by the Community Exposure and Health Effects Assessment Program was ongoing monitoring of personal exposure levels to contaminants produced by industrial development. AHW stated that it had been working with WBEA over the last two and one-half years to implement the recommendation, but deployment was delayed many times due to funding, issues of science, and the need to recruit volunteers to participate in the ongoing monitoring.

With respect to a baseline health study, AHW commented that a standalone health study for Fort Chipewyan would not provide much value. AHW stated that a program was needed that provided ongoing monitoring of health effects associated with contaminants. This approach would include accessing physicians' claims data and hospitalization data to obtain a baseline perspective on the overall health of the community, which in turn would be linked to the ongoing monitoring program.

AHW offered to assist MCFN in its efforts to establish a baseline for the health of the community and indicated it would continue to work with WBEA to implement an ongoing health-monitoring program that would include many of the First Nations, Metis, and other aboriginal people living in the region.

AHW believed that the health of the public would not be compromised by the construction and operation of the project.

24.6 Views of the Panel

The Panel accepts that the health risk assessment conducted by Shell was appropriate and reasonable. Given the conservatism of the modelling, it also accepts the conclusion that there will be no health risks associated with the construction and operation of the project. The Panel does acknowledge the comments about health and health concerns brought forward by various interveners. In light of the existing and planned industrial development for the area, the Panel agrees that additional baseline health data and ongoing health effects monitoring are warranted. The Panel believes that improved baseline health information is needed, especially for First Nations, Metis, and other aboriginal groups, so that any incremental health effects can be measured and appropriate action taken. This would help validate the modelling results and would serve to improve confidence in the human health risks assessment.

In addressing this issue, the Panel acknowledges that the primary investigative and decision-making responsibilities reside with AHW and HC, and it looks to these departments to validate the need for and to develop a regional health assessment strategy that includes all affected stakeholders. The Panel also notes that both governments have indicated their support for an ongoing health effects monitoring program. With this in mind, the Panel recommends that AHW and HC consider undertaking a regional baseline health study primarily dealing with First Nations, Metis, and other aboriginal groups and consider contributing expertise and funding in support of WBEA's efforts to implement an ongoing health-monitoring program consistent with the recommendation of the Alberta Oil Sands Community Exposure and Health Effects Assessment Program. Further, the Panel expects Shell to meet its commitment to MCFN to fully support and participate in any health assessment program. The Panel believes that the implementation of a health assessment program must include a communications component, so that results of the research are communicated to participants and the public on an ongoing basis.

The Panel concludes that with the implementation of proposed mitigation measures and attention to the Panel's recommendations, the project is unlikely to result in significant adverse human health effects.

25 CULTURAL AND HERITAGE RESOURCES

25.1 Views of Shell

Shell stated that the EIA completed for the project included a historical resources component and a standalone HRIA completed and then reviewed by Alberta Community Development (ACD). The HRIA evaluated the specific resources effects of the first ten years of the project operations and made recommendations with respect to the assessment needs of subsequent stages of project development, as well as mitigation of specific negative effects.

The analysis conducted for the HRIA indicated there would be a moderate to high negative effect until ACD established the required mitigation. However, Shell believed that once the mitigation measures had been implemented, the negative historical resources effects of the project would be negligible.

25.2 Views of the Panel

The Panel is satisfied that the cultural and historical impacts were addressed in a reasonable way and it believes that it is appropriate for Shell to work directly with ACD to establish the remaining historical resources requirements.

The Panel concludes that the project is not likely to have significant adverse effects on cultural and heritage resources provided the proposed mitigation measures ACD approves are implemented.

26 PUBLIC CONSULTATION

26.1 Views of Shell

Shell stated that over the past two years it had consulted extensively with the regulators and key stakeholders on the predicted environmental effects of the project. It stated that its consultation effort included both the individuals and groups that would be directly affected by the project and those that demonstrated an interest in the project, including local communities, First Nations and Metis leaders and organizations, environmental nongovernmental organizations, special interest groups, the RMWB, regulators, government agencies, and industry.

Shell indicated that it had provided information about the project through meetings, workshops, forums, open houses, public documents, information handouts, a toll-free telephone line, speaking engagements, and advertisements. Shell noted that the concerns of its neighbours had been addressed where mutually agreeable solutions could be reached and pointed to the fact that it had environmental partnerships and agreements in place with Fort McKay, ACFN, and OSEC that addressed environmental concerns and provided for further involvement in the development of the project. Shell stated that WBFN had a number of opportunities to participate in the consultation process, but it chose not to participate. Shell stated that WBFN wanted Shell to meet certain conditions prior to any consultation process. Shell did not believe that these conditions were appropriate.

26.2 Views of OSEC

OSEC indicated that it began its review of the EIA in September 2001. OSEC believed that this process enabled it to gain a better understanding of the project and it believed that Shell had gained a better understanding of OSEC's concerns. OSEC stated that it had reached an agreement with Shell.

26.3 Views of MCFN

MCFN stated that it had a long-term relationship with Shell and that it had been working towards an agreement with Shell for a number of months. It pointed out that although it initially had criticisms of the EIA, it believed that Shell remained committed to working toward an agreement with MCFN. In its view, the personal relationship and trust MCFN had with Shell was a key factor in resolving its concerns about the project and coming to an agreement just before the hearing began.

26.4 Views of WBFN

WBFN asserted that it was an aboriginal group that was entitled to be consulted in a meaningful manner. WBFN stated that it had entered into an agreement with Shell that provided a process for WBFN to bring forward any concerns it had with respect to the project. However, WBFN also indicated that it had tried unsuccessfully to reach a separate agreement with Shell that would provide for an ongoing relationship between the two parties. Therefore, WBFN stated that until it reached a meaningful consultation agreement with Shell, it was opposed to the project.

26.5 Views of ACFN

In closing argument, ACFN stated that it enjoyed a positive consultative relationship with Shell and that it looked forward to working with Shell in the future on its agreement.

26.6 Views of Fort McKay

In closing argument, Fort McKay indicated that Shell had been and continued to be a good neighbour to the community of Fort McKay. It stated that Shell had honoured its commitments in relation to the Muskeg River Mine, and it believed that Shell would continue to deal with the community in good faith.

26.7 Views of the Panel

The Panel believes that overall Shell has done an outstanding job of public consultation, involving both those potentially affected and those expressing an interest in the project. The Panel recognizes the proactive approach to participant involvement taken by Shell early in the project development process. Shell demonstrated to the Panel that, where possible, concerns raised by interested parties have been incorporated into the development of the project and into the planned mitigation and monitoring. The Panel also acknowledges the support Shell has provided to regional issues management groups, such as CEMA and its working groups.

The Panel expects all stakeholders in the region to be consulted. The Panel believes that Shell has taken reasonable steps to engage WBFN in the consultation process.

27 CAPACITY OF RENEWABLE RESOURCES

27.1 Views of Shell

Shell's resource use assessment considered several resources and resource uses that could be potentially impacted by the project. Shell evaluated the capability for the use of renewable resources in terms of both availability and accessibility for traditional and nontraditional users.

Shell indicated that road access within the project development area as a result of existing oil sands activities and gas exploration and production operations would have an effect on resource use. Shell stated that site clearing for the mine site and facilities within the project area might reduce resource availability, while changes to the local road system might increase or decrease access to resources. Shell's assessment also considered the increase in the local area workforce and how that might affect resource use. Shell indicated that to use natural resources, the resources themselves must be available and users must have access to them. For each type of resource use, Shell considered relevant government guidelines, available resource use statistics, and important locations in which resources were located in the RSA and LSA. Shell considered three cases in its resource use assessment: a baseline case, an application case, and a planned development case.

Shell indicated that increases in the region's population under both the application case and the planned development case would have implications for all types of resources in the RSA. These effects included increased demand for fishing, hunting, berry picking, and recreation. While effects of these changes were low under the application case, they were considered moderate under the planned development case.

Shell indicated that there were no agricultural activities in the LSA and minimal agricultural activity within the RSA. The agriculture within the RSA was limited to grazing, market gardens, and wild rice operations.

Shell indicated that the effects on forestry as a result of the project would occur due to clearing of forests in the LSA. Shell indicated that trees would be lost from the development footprint for the life of the project and merchantable timber would be salvaged during site clearing. Shell stated that reclamation of the development area was expected to return the area to equivalent or greater capability. Forest regeneration to commercial standards would require 50 years for aspen and 80 to 120 years for coniferous species. Following closure, Shell indicated that the productive forest stands would be restored through reclamation and the regenerated forest would not be available for harvesting for 120 years. As compensation would be provided to the companies affected, Shell concluded that the overall consequence for both resource use and resources users was considered negligible for forestry.

Shell stated the project would result in a temporary loss of wildlife habitat during and in some cases extending several years past the life of the project, as 63 per cent of the LSA would be cleared. Shell stated that access to the area would be replaced through a new access corridor to be determined through multistakeholder consultation. Shell concluded that based on measures of both potential resource use and current resource users, the overall environmental consequence to hunting was negligible.

Shell indicated that the project would result in a temporary loss of furbearer habitat during and in some cases extending several years past the life of the project. This localized habitat loss would have the potential to affect some trappers in the region but was rated by Shell as a negligible environmental consequence. Shell stated that it had met with all affected trappers and it planned to continue to consult with trappers to address their concerns. Shell stated that it was participating with the Sustainable Ecosystems Working Group (SEWG) to understand and manage the cumulative regional effects on wildlife and fish populations, as well as those on hunters, trappers, and fishermen.

Shell assessed berry picking by analyzing the impacts on the berry producing plants. Each vegetation type within the terrestrial LSA that was considered to have berry-producing potential was determined and the effects were evaluated. Compared to the RSA as a whole, the LSA had a relatively small proportion of blueberry habitat and a relatively high proportion of cranberry habitat. Berry-picking activity was limited by restricted road access within both the LSA and RSA. Shell indicated that approximately 1610 ha of berry habitat would be affected by clearing for the project, representing 56 per cent of the potential berry-picking area in the LSA. However, less than 2 per cent of berry harvesters in the region used berry patches in or near the LSA, and the area cleared was 0.25 per cent of the potential berry-picking area in the RSA as a whole. Shell concluded that the environmental consequence to berry picking was therefore negligible. Shell stated that after reclamation occurred, the total amount of potential berry habitat was projected to increase to 4650 ha.

Shell identified that two watercourses had been documented in the LSA as sport fishing locations (the Muskeg River and Jackpine Creek) and one lake was known to support a sportfish population (Kearl Lake). It pointed out that the Muskeg River was accessible by an all-weather road and contained whitefish, perch, northern pike, Arctic grayling, walleye, and mountain whitefish. Shell stated that Jackpine Creek was accessible by road, quad, and snowmobile and had a northern pike population, but was not listed as a fishing location by any potential users. Kearl Lake was accessible by road and had a northern pike population, but had not been listed as a fishing location by any fishers. Shell indicated that no fishing destinations known to support sportfish or fishing areas would be directly affected by site-clearing activities. Shell also indicated that with an increase in upland and lake habitat areas, it was likely that hunting, trapping, and fishing capability after reclamation would also be equivalent or greater than predevelopment levels.

27.2 Views of the Panel

The Panel believes that for each renewable resource that could be affected, Shell has proposed adequate mitigation. The Panel also believes that given the nature of the project, the mitigation measures that will be implemented, and the recommendations of the Panel, the project is not likely to cause significant adverse environmental effects on renewable resources. Accordingly, the Panel concludes that the capacity of those resources to meet the needs of the present and those of the future is not likely to be significantly affected.

28 COGENERATION PLANT AND FRESH WATER PIPELINE (APPLICATIONS NO. 1271207 AND 1271383)

Application No. 1271207 is for approval for an electrical power plant to be located at the project site. Application No. 1271383 is for approval for an 8.5 km fresh water pipeline from LSD 02-23-95-10 W4M to LSD 08-16-95-10 W4M. There were no specific issues raised with respect to these applications.

28.1 Views of Shell

Shell stated that it was applying for a nominal 160 MW cogeneration plant consisting of a single natural gas combustion turbine and generator set and a heat recovery steam generator that would recover heat from the turbine's exhaust gases to produce process steam. Shell stated that it sized the cogeneration plant to meet the mine's electrical requirements and that the plant would provide approximately 40 per cent of the thermal demands for the processing plant. Two natural gas-fired auxiliary boilers would supply additional heat for the process.

Shell projected a maximum peak electric consumption of 170 MW at the start of operations in 2010, increasing to 189 MW in 2013 and to 203 MW in 2018. Therefore, all the plant's electric generation would be consumed within the project. Shell did not anticipate exporting electric energy to the Alberta Electric System from the project. Shell recognized that power exports or changes to the cogeneration plant from what it proposed in the application would have to be approved by the EUB, by way of an amendment to the plant approval. Shell did not expect to change the size or type of plant from what was stated in the application.

Shell indicated in its application that the electrical load not supplied by the proposed cogeneration plant would be supplied from the Alberta Electric System or directly from the existing Muskeg River cogeneration plant via a new 260 kilovolt (kV) transmission line. Shell acknowledged that additional approvals, under Sections 14, 15, and 18 of the Hydro and Electric Energy Act, would be required to construct and operate new transmission facilities and to connect the plant to the Alberta Electric System. Shell also indicated in its application that if it decided to exchange electric energy directly with the Muskeg River Mine and not through the Alberta Electric System, it would have to obtain an Industrial System Designation exception pursuant to Section 4 of the Hydro and Electric Energy Act.

Shell indicated that the fresh water pipeline would be needed to transport Athabasca River water from the Muskeg River Mine site to the proposed plant site. Shell stated that two new pumps would be added to the existing Muskeg River Mine pump house to increase the volume delivered to the Muskeg River Mine site. Shell stated that the existing water intake for the Muskeg River Mine was sufficient to accommodate both projects and therefore no structural changes would be required. Shell noted that arrangements for sharing the common system from the river intake to the Muskeg River Mine would be contained in a written agreement with Albian Sands.

Shell stated that the pipeline would be a butt-welded steel pipe with an outside diameter of 1067 millimetres (mm), a wall thickness of 12.7 mm, and an abrasion-resistant liner. Shell proposed that the pipeline would be buried, except for two portions totaling 120 m where the pipeline would cross the Muskeg River and Jackpine Creek on bridges.

Shell stated that it proposed to start construction of the pipeline in the winter of 2008 and complete construction by early 2010. Shell noted that under Section 13 of the Pipeline Act the EUB had the ability to set the date by which construction of the pipeline should commence.

Shell requested that the EUB issue a pipeline licence that would be in effect concurrently with the other licences issued by the EUB for the project.

28.2 Views of the Panel

The Panel notes that none of the interveners raised any issues regarding the cogeneration plant or the fresh water pipeline.

The Panel notes that Shell is planning on using all the power from the cogeneration plant at the Jackpine Mine, is not anticipating any export of electricity from the project, and is aware that any change in the cogeneration plant from what is proposed in the application would require Shell to apply to amend its approval. The Panel also notes that the power plant is just one of several contributors to total air emissions from the project. The Panel has already addressed air emissions in Section 14.6 and believes that there is unlikely to be any significant adverse environmental effects to air quality as a result of the project provided the mitigation measures are implemented. Therefore, the Panel approves Application No. 1271207 and will issue an approval pursuant to Section 11 of the Hydro and Electric Energy Act in due course.

The Panel also notes that additional approvals would be required to construct and operate the transmission facilities necessary to connect the plant to the Alberta Electric System and to exchange electric energy with the Muskeg River Mine.

The Panel is satisfied with the proposed fresh water pipeline. Therefore, the Panel approves Application No. 1271383 and will issue an approval pursuant to Part 4 of the Pipeline Act in due course. The Panel expects that the pipeline would be constructed prior to 2010 and it will state that the pipeline permit is valid until January 1, 2010. If the pipeline has not been constructed prior to that date, Shell will be required to apply to the EUB for an extension to its pipeline permit.

Dated in Calgary, Alberta, on February 5, 2004.

ALBERTA ENERGY AND UTILITIES BOARD
CANADIAN ENVIRONMENTAL ASSESSMENT AGENCY

J. D. Dilay, P.Eng.
Panel Chair

George Kupfer

G. Kupfer, Ph.D.
Panel Member

R. Houlihan

R. Houlihan, Ph.D., P.Eng.
Panel Member

APPENDIX 1 SUMMARY OF EUB APPROVAL CONDITIONS AND COMMITMENTS

CONDITIONS

- Shell shall submit a lease boundary report five years prior to mining activities reaching any common lease boundary. The report must include a comprehensive description of the lease boundary geology and reserves, geotechnical conditions, alternative mining scenarios and impacts, and the costs associated with each, all in accordance with Section 3.1 of EUB *Interim Directive (ID) 2001-7: Operating Criteria: Resource Recovery for Oil Sands Mines and Processing Sites* (Section 6.2.2).

- Shell shall submit, for EUB approval, an access road and utility corridor update in its 2006 annual report. The report shall include a resource assessment of the oil sands located in the Sharkbite area and under the modified infrastructure corridor. It shall also include a comparison of alternative access road and utility corridor alignments with respect to resource recovery and other relevant criteria (Section 6.3.2).

- Shell shall submit, for EUB approval, a resource assessment of the plant site area two years prior to construction (Section 6.3.2).

- Shell shall submit, for EUB approval, detailed geotechnical design for all external overburden disposal areas at least six months prior to field preparation in those areas (Section 6.4.2).

- Shell shall submit, for EUB approval, a resource assessment of the three waste disposal areas and reclamation material stockpile two years prior to material placement (Section 6.4.2).

- Shell shall submit, for EUB approval, a ten-year mine plan and material balance by the earlier of 2008 or six months prior to pit development (Section 6.4.2).

- Shell must satisfy the EUB, two years prior to construction of either the Khahago surge facility or the tailings disposal area, that the design of the tailings disposal area, including the surge facility, provides for adequate capacity, stability, and minimization of resource sterilization and environmental impact (Section 6.7.2).

- Shell shall provide an annual report to the EUB on the status of the project and its development commencing on February 28, 2005, or such other date and frequency the EUB may stipulate (Section 6.8.2).

- Shell shall provide a report on progress in improving the bitumen extraction recovery in every second annual report to the EUB starting in 2008, or such other date and frequency the EUB may stipulate (Section 7.3).

- Shell shall continue to evaluate tailing solvent recovery unit (TSRU) thickeners technology and report results to the EUB in the 2006 annual report. The report must identify any opportunities to include TSRU thickeners in the project design and construction (Section 7.3).

- Shell shall report on its progress in dealing with separation characteristics of asphaltenes in the TSRU tailings in its annual report to the EUB commencing in 2005, or such other date and frequency the EUB may stipulate (Section 7.3).
- On or before February 28 of each year commencing in 2011, Shell shall provide to the EUB a summary of the previous year's operation stating the amount of asphaltene rejected. The amount of asphaltenes rejection shall be limited to 10 mass per cent based on bitumen production (Section 7.3).
- On an annual average basis, Shell must limit site-wide solvent losses to not more than 4 volumes per 1000 volumes of bitumen production under all operating conditions. Shell shall not discharge untreated froth treatment tailings to the tailings disposal area (Section 7.3).
- Shell shall submit a report to the EUB prior to final design or June 30, 2006, whichever is earlier, on the feasibility of producing consolidated tailings (CT) on commencement of operation in order to reduce the accumulation of thickened tailings, thin fine tails, and mature fine tails (Section 8.2).
- Shell shall describe its progress on developing solid tailings technology in every second annual report to the EUB, commencing on February 28, 2005, or such other date and frequency the EUB may stipulate (Section 8.2).
- Shell shall submit to the EUB a report summarizing the engineering design and operating plans for the CT system two years prior to planned start-up, or such other date the EUB may stipulate (Section 8.2).
- Shell shall submit to the EUB on or before February 28 of every year commencing in 2011, or such other date or frequency the EUB may stipulate, a report summarizing the performance of the tailings management system during the preceding year, including Shell's reasons for any deviations from design (Section 8.2).
- Shell shall provide a report, for EUB approval, detailing its mine plans near the Pleistocene Channel aquifer (PCA) five years prior to mining in this area to allow for the consideration of resource recovery issues and environmental impacts. The report shall include the proposed location of the pit limits and their proximity to the PCA, as well as a description of any mitigation that would be completed to minimize the impact of mining near the PCA (Section 13.1.6).
- Shell shall provide an annual report on regional development cooperation to the EUB starting in 2005. The report shall describe guiding principles and activities for cooperative development, opportunities and constraints of collaborative work among developers, specific time frames and implementation steps for all project phases to integrate them with other oil sands projects in the Muskeg River basin, and the means to evaluate outcomes (Section 18.4).

COMMITMENTS

The Panel notes throughout the report that Shell has undertaken to conduct certain activities in connection with its operations that are not strictly required by EUB, AENV, or DFO regulations or guidelines. These undertakings are described as commitments.

The Panel believes that when a company makes commitments of this nature, it has satisfied itself that these activities will benefit both the project, stakeholders, and the public, and the Panel takes these commitments into account when arriving at its decision. The Panel expects that Shell will adhere to all commitments it made during the consultation process, in the application, and at the hearing, to the extent that those commitments do not conflict with the terms of any approval or licence affecting the project or any law, regulation, or similar requirement Shell is bound to observe. The Panel expects Shell to advise the EUB if, for whatever reasons, it cannot fulfill a commitment. The EUB would then assess whether the circumstances regarding the failed commitment warrant a review of the original approval. The EUB also notes that the affected parties also have the right to request a review of the original approval if commitments made by the applicant remain unfulfilled.

In addition to any commitments it made at the hearing, Shell provided Exhibit No. 12, listing in detail its commitments to stakeholders and regulators in the areas of operational management, environmental management, socioeconomic initiatives, and consultation.

APPENDIX 2 PANEL AGREEMENT

AGREEMENT

To Establish a Joint Review Panel for the Jackpine Mine Project

Between

The Minister of the Environment, Canada

- and -

The Alberta Energy and Utilities Board

PREAMBLE

WHEREAS the Alberta Energy and Utilities Board (the AEUB) has statutory responsibilities pursuant to the *Alberta Energy and Utilities Board Act* and the *Energy Resources Conservation Act*; and

WHEREAS the Minister of the Environment, Canada (the Federal Minister) has statutory responsibilities pursuant to the *Canadian Environmental Assessment Act*; and

WHEREAS the Jackpine Mine Project (the Project) requires a public hearing and approvals from the AEUB pursuant to the *Alberta Energy and Utilities Board Act* and the *Energy Resources Conservation Act* and is subject to an assessment under the *Canadian Environmental Assessment Act*; and

WHEREAS the Minister of Fisheries and Oceans has referred the environmental assessment in respect of the Project to the Federal Minister in accordance with section 21 of the *Canadian Environmental Assessment Act*; and

WHEREAS the Federal Minister has referred the project to a review panel in accordance with section 29 of the *Canadian Environmental Assessment Act*; and

WHEREAS the Government of the Province of Alberta and the Government of Canada established a framework for conducting joint panel reviews through the *Canada-Alberta Agreement for Environmental Assessment Cooperation* signed on June 30, 1999; and

WHEREAS the AEUB and the Federal Minister have determined that a joint panel review of the Project will ensure that the project is evaluated according to the spirit and requirements of their respective authorities while avoiding unnecessary duplication, delays and confusion that could arise from separate reviews by each government; and

WHEREAS the AEUB and the Federal Minister have determined that a joint panel review of the Project should be conducted in a manner consistent with the provisions of the *Subsidiary Agreement on Joint Review Panels*, attached as Appendix 2 of the *Canada-Alberta Agreement for Environmental Assessment Cooperation*; and

WHEREAS the Federal Minister has determined that a joint review panel should be established pursuant to paragraph 40(2) of the *Canadian Environmental Assessment Act* to consider the Project;

THEREFORE, the AEUB and the Federal Minister hereby establish a joint review panel for the Project in accordance with the provisions of this Agreement and the Terms of Reference attached as an Appendix to this Agreement.

1. Definitions

For the purpose of this Agreement and of the Appendix attached to it,

"**Agency**" means the Canadian Environmental Assessment Agency.

"**EIA Report**" means an Environmental Impact Assessment report prepared in accordance with the Terms of Reference issued for the Project by the Director of Alberta Department of the Environment.

"**Environment**" means the components of the Earth, and includes
(a) land, water and air, including all layers of the atmosphere;
(b) all organic and inorganic matter and living organisms; and
(c) the interacting natural systems that include components referred to in (a) and (b)."

"**Environmental Effect**" means, in respect of the Project,
(a) any change that the Project may cause in the Environment, including any change it may cause to a listed wildlife species, its critical habitat or the residence of individuals of that species, as those terms are defined in subsection 2(1) of the *Species at Risk Act*,
(b) any effect of any change referred to in paragraph (a) on
  (i) health and socio-economic conditions
  (ii) physical and cultural heritage
  (iii) the current use of lands and resources for traditional purposes by aboriginal persons
  (iv) any structure, site or thing that is of historical, archeological, paleontological or architectural significance, or
(c) any change to the project that may be caused by the environment

whether any such change or effect occurs within or outside Canada.

"**Federal Authority**" refers to such an authority as defined in the *Canadian Environmental Assessment Act.*

"**Final Report**" is the document produced by the Joint Panel, which contains decisions pursuant to the *Energy Resources Conservation Act* and the Joint Panel's conclusions and recommendations pursuant to the *Canadian Environmental Assessment Act* with respect to the environmental assessment of the Project.

"**Follow-up Program**" means a program for

(a) verifying the accuracy of the environmental assessment of the Project, and

(b) determining the effectiveness of any measures taken to mitigate the adverse environmental effects of the Project.

"**Joint Panel**" refers to the joint panel established by the AEUB and the Federal Minister through this Agreement.

"**Mitigation**" means, in respect of the Project, the elimination, reduction or control of the adverse environmental effects of the project, and includes restitution for any damage to the environment caused by such effects through replacement, restoration, compensation or any other means.

"**Parties**" means the signatories to this Agreement.

"**Responsible Authority**" refers to such an authority as defined in the *Canadian Environmental Assessment Act.*

2. Establishment of the Panel

2.1. A process is hereby established to create a Joint Panel, pursuant to section 22 of the *Energy Resources Conservation Act* with the authorization of the Lieutenant Governor in Council of Alberta, and Sections 40, 41 and 42 of the *Canadian Environmental Assessment Act*, for the purposes of the review of the Project.

2.2. The AEUB and the Agency will make arrangements to coordinate the announcements of a joint review of the Project by both Alberta and Canada.

3. Constitution of the Panel

3.1. The Joint Panel will consist of three members. Two members, including the Joint Panel Chair, will be appointed by the Chair of the AEUB with the approval of the Federal Minister. The third Joint Panel member will be appointed by the Federal Minister in accordance with article 3.2 of this Agreement.

3.2. The Federal Minister will select the third Joint Panel member and recommend the selected candidate as an individual who may serve as a potential acting member of the AEUB. If acceptable to the Lieutenant Governor in Council of Alberta and the Chairman of the AEUB, the Lieutenant Governor in Council of Alberta will nominate this candidate to serve as an acting member of the AEUB and the Chairman of the AEUB will appoint this candidate as a member of the Joint Panel. The selected candidate will then be appointed by the Federal Minister as a member of the Joint Panel.

3.3. The Joint Panel members shall be unbiased and free from any conflict of interest relative to the Project and are to have knowledge or experience relevant to the anticipated Environmental Effects of the Project.

4. Conduct of Assessment by the Panel

4.1. The Joint Panel shall conduct its review in a manner that discharges the responsibilities of the AEUB under the *Alberta Energy and Utilities Board Act* and the *Energy Resources Conservation Act*.

4.2. The Joint Panel shall conduct its review in a manner that discharges the requirements set out in the *Canadian Environmental Assessment Act* and in the Terms of Reference attached as an Appendix to this Agreement.

4.3. All Joint Panel hearings shall be public and the review will provide for public participation.

4.4. The Joint Panel shall have all the powers and duties of a panel described in Section 35 of the *Canadian Environmental Assessment Act* and in Section 10 of the *Alberta Energy and Utilities Board Act*.

5. Secretariat

5.1. Administrative, technical, and procedural support requested by the Joint Panel shall be provided by a Secretariat, which shall be the joint responsibility of the AEUB and the Agency.

5.2. The Secretariat will report to the Joint Panel and will be structured so as to allow the Joint Panel to conduct its review in an efficient and cost-effective manner.

5.3. The AEUB will provide its offices for the conduct of the activities of the Joint Panel and the Secretariat.

6. Record of Joint Review and Final Report

6.1. A public registry will be maintained by the Secretariat during the course of the review in a manner that provides for convenient public access, and for the purposes of compliance with section 55 of the *Canadian Environmental Assessment Act*. This registry will be located in the offices of the AEUB.

6.2. On completion of the assessment of the Project, the Joint Panel will prepare a Final Report.

6.3. Once completed, the Final Report will be conveyed, in both official languages simultaneously, by the Joint Panel to the Government of Alberta, to the Federal Minister, the Minister of Fisheries and Oceans, and to the public.

6.4. Once the Final Report is submitted to the Federal Minister, the responsibility for the maintenance of the public registry will be transferred to the Responsible Authority. The AEUB will continue to maintain records of the proceedings and the Final Report, as per the AEUB Rules of Practice.

7. Other Government Departments

7.1. At the request of the Joint Panel, Federal Authorities and provincial authorities having specialist knowledge with respect to the Project will provide available information and knowledge in a manner acceptable to the Joint Panel.

7.2. Nothing in this agreement will restrict the participation by way of submission to the Joint Panel by other federal or provincial government departments or bodies, subject to article 7.1, above, section 12(3) of the *Canadian Environmental Assessment Act* and the AEUB Rules of Practice.

8. Participant Funding

8.1. Decisions regarding participant funding by the Agency under the federal Participant Funding Program, and decisions on intervener funding by the AEUB as provided for in the *Energy Resources Conservation Act*, AEUB Rules of Practice and the AEUB Guidelines for Energy Cost Claims (Guide 31A) will, to the extent practicable, take into account decisions of the other party.

9. Cost Sharing

9.1. The AEUB, as lead party, will develop a budget estimate of expenses agreeable to both parties prior to initiation of Joint Panel activities.

9.2. The costs of the review will be apportioned between the AEUB and the Agency in the manner set out in articles 9.3, 9.4 and 9.5.

9.3. The AEUB will be solely responsible for the following costs:

- salaries and benefits of the Joint Panel Chairman and the member of the Joint Panel not appointed in accordance with article 3.2; and
- salaries and benefits of AEUB staff involved in the joint review.

9.4. The Agency will be solely responsible for the following costs:

- per diems of the Joint Panel member appointed in accordance with article 3.2;
- salaries and benefits of Agency staff involved in the joint review;
- all costs associated with the federal Participant Funding Program; and
- French translation requirements.

9.5. The AEUB and the Agency agree to share equally all those costs listed below, incurred as part of the Joint Panel review from the signing of this Agreement to the date the Final Report is issued by the Joint Panel. The shareable costs are as follow:

- travel-related expenses associated with the review incurred by the Joint Panel members, and by AEUB and Agency staff in fulfilling the Secretariat functions;
- per diems and associated expenses of independent/non-government expert consultants or communications specialists retained by the Joint Panel;
- printing of any reports or documents distributed by the Joint Panel necessary for the Joint Panel's work;
- the publication of notices;
- photocopying and postage related to the review;
- production of one electronic and one paper copy of the transcripts prepared by court reporters as required by the Joint Panel;
- rental of hearing and public meeting facilities and equipment;
- sound services at the hearing and public meetings; and
- miscellaneous expenditures up to a maximum of 5 percent of the total budget for the review.

9.6. Shareable costs of the joint review as detailed in article 9.5 will be incurred at the sole discretion of the Joint Panel with due regard to economy and efficiency.

9.7. All expenses not listed above will need prior approval of both parties if they are to be equally shared.

9.8. To facilitate the delivery of payment of per diems of the Joint Panel member appointed in accordance with article 3.2 the AEUB will pay the individual in response to appropriate invoices and will invoice the Agency for the reimbursement of such payments.

10. Amending this Agreement

10.1. The terms and provisions of this agreement may be amended by written memorandum executed by both the Federal Minister and the Chairman of the AEUB. Subject to section 27 of the *Canadian Environmental Assessment Act*, upon completion of the joint review, this Agreement may be terminated at any time by an exchange of letters signed by both parties.

11. Signatures

WHEREAS the parties hereto have put their signatures this 18th day of August 2003.

<original signed by>

The Honourable David Anderson
Minister of the Environment

<original signed by>

Neil McCrank
Chairman
Alberta Energy and Utilities Board

Appendix
Terms of Reference

Part I - Project Description

Shell Canada Limited is proposing to construct and operate an oil sand mining and extraction facility. The proposed Jackpine Mine is to be located approximately 70 kilometres north of Fort McMurray in Townships 95, Ranges 8 to 9, West of the 4th Meridian. The proposed development includes an open pit, truck and shovel mine, bitumen processing train, a co-generation plant consisting of 170-megawatt gas turbine generator fitted with a heat recovery steam boiler, infrastructure associated with the mine and facility, water and tailing management plans, and an integrated reclamation plan. The Jackpine Mine is designed to produce approximately 31 800 cubic metres per day of bitumen from the McMurray Formation. The Jackpine Mine is expected to have full production in 2010 and last 22 years. Shell is also proposing to construct and operate of a 8.5 km fresh water pipeline from LSD 2-23-95-10 W4M to LSD 08-16-95-09 W4M.

Part II - Scope of the Environmental Assessment

1. The Joint Panel will conduct an assessment of the Environmental Effects of the Project based on the Project Description (Part I).

2. The assessment will include a consideration of the factors listed in subsection 16(1)(a) to (d) and 16(2) of the *Canadian Environmental Assessment Act*, namely:
    - **a)** The environmental effects of the Project, including the environmental effects of malfunctions or accidents that may occur in connection with the Project and any cumulative environmental effects that are likely to result from the Project in combination with other projects or activities that have been or will be carried out;
    - **b)** The significance of the effects referred to in paragraph a);
    - **c)** Comments from the public that are received during the review;
    - **d)** Measures that are technically and economically feasible and that would mitigate any significant adverse environmental effects of the Project;
    - **e)** The purpose of the Project;
    - **f)** Alternative means of carrying out the Project that are technically and economically feasible and the environmental effects of any such alternative means;
    - **g)** The need for, and the requirements of, any follow-up program in respect of the Project; and
    - **h)** The capacity of renewable resources that are likely to be significantly affected by the Project to meet the needs of the present and those of the future.

3. Pursuant to subsection 16(1)(e) of the CEAA, the assessment by the Joint Panel will also include a consideration of the additional following matters:

   a) Need for the Project;
   b) Alternatives to the Project; and
   c) Measures to enhance any beneficial environmental effects.

4. The Review will consider the Environmental Effects of the proposed Project within spatial and temporal boundaries which encompass the periods and areas during and within which the Project may potentially interact with, and have an effect on, components of the environment. These boundaries may vary with the issues and factors considered, and with the different phases in the life cycle of the project. The boundaries will reflect:

   - the natural variation of a population or ecological component;
   - the timing of sensitive life cycle phases in relation to the scheduling of the Project;
   - the time required for an effect to become evident;
   - the time required for a population or ecological component to recover from an effect and return to a pre-effect condition, including the estimated degree of recovery;
   - the area affected by the Project; and
   - the area within which a population or ecological component functions and within which a Project effect may be felt.

APPENDIX 3 HEARING PARTICIPANTS

Principals and Representatives (Abbreviations used in report)	Witnesses
Shell Canada Limited (Shell) S. Denstedt K. Lozynsky B. Gilmour J. Cartwright	K. Firmin, P.Eng. A. Vanderputten, P.Eng. L. Nehring N. Camarta, P.Eng. R. Seeley, P.Eng. J. Smith, P. Biol. J. Gulley K. Thompson M. Trudell, Ph.D., P.Geol. M. Ingen-Houz M. Rawlings, P.Eng. S. McKenzie, P.Biol. M. Digel F. Ade, Ph.D., P.Eng. A. Beersing, Ph.D., P.Eng.
Oil Sands Environmental Coalition (OSEC) K. Buss	D. Woynillowicz
Athabasca Chipewyan First Nation (ACFN) K. Buss	
Fort McKay First Nation and Metis Local # 122 (Fort McKay) K. Buss	
Fort McMurray Medical Staff Association (FMMSA) M. Sauvé, M.D.	M. Sauvé, M.D.
Sierra Club of Canada (SCC) S. P. Stensil E. May	E. May

(continued)

APPENDIX 3 HEARING PARTICIPANTS (continued)

Principals and Representatives (Abbreviations used in report)	Witnesses
Mikisew Cree First Nations (MCFN) D. Mallon R. Salamucha	Chief A. Waquan W. Courtorielle A. Courtorielle Dr. P. Komers, Ph.D. Dr. E. Dickson Dr. J. Byrne, D.Phil. Dr. S. Kienzle, Ph.D. J. Brownlee, M.E.S. B. Evans V. McKay
Wood Buffalo First Nation (WBFN) J. Malcolm	J. Malcolm R. Woodward W. Castor G. Castor J. Grant
Canadian Natural Resources Limited (CNRL) D. A. Holgate	
Imperial Oil Resources and ExxonMobil Canada (ExxonMobil) K. Sury	
Syncrude Canada Limited (Syncrude) B. Roth D. Bercov	
Suncor Energy Limited (Suncor) S. Lowell	
UTS Energy Corp. (UTS) D. McDonald	

(continued)

APPENDIX 3 HEARING PARTICIPANTS (continued)

Principals and Representatives (Abbreviations used in report)	Witnesses
Government of Canada (Canada) D. Mueller B. Hughson	Department of Fisheries and Oceans (DFO) Panel R. Courtney, P.Biol. D. Majewski B. Makowechi D. Walker J. Shamess A. Thomson, P.Eng. Environment Canada (EC) Panel M. Fairbairn L. Bates-Frymel P. Gregoire D. Linderman, Ph.D. B. Brownlee, Ph.D. B. Coutts Natural Resources Canada (NRCAN) Panel L. Wells Health Canada (HC) Panel L. Liu, Ph.D. O. Vuzi Indian and Northern Affairs Canada Panel K. Maksymiec
Her Majesty the Queen in Right of Alberta (Alberta) D. Stepaniuk H. Veale K. Sandstrom	Alberta Environment (AENV) Panel B. Pretula C. de la Chevrotiere, P.Eng. M. Boyd R. Barrett L. Rhude, P.Biol. K. Singh, P.Eng. P. Marriott, P.Eng. Alberta Sustainable Resource Development (ASRD) Panel R. Chabaylo, P.Biol. C. Hale, RPF P. McEachern, Ph.D. Alberta Health and Wellness (AHW) Panel A. MacKenzie Dr. K. Bodo, Ph.D.

(continued)

APPENDIX 3 HEARING PARTICIPANTS (concluded)

Principals and Representatives (Abbreviations used in report)	Witnesses
Alberta Energy and Utilities Board (EUB) staff G. Perkins, Board Counsel A. Larson, P.Eng. P. Hunt M. Woytiuk M. Dmytriw, R.E.T. C. Brown, P.Biol. W. MacKenzie T. Lemay	
Canadian Environmental Assessment Agency staff S. Chapman	

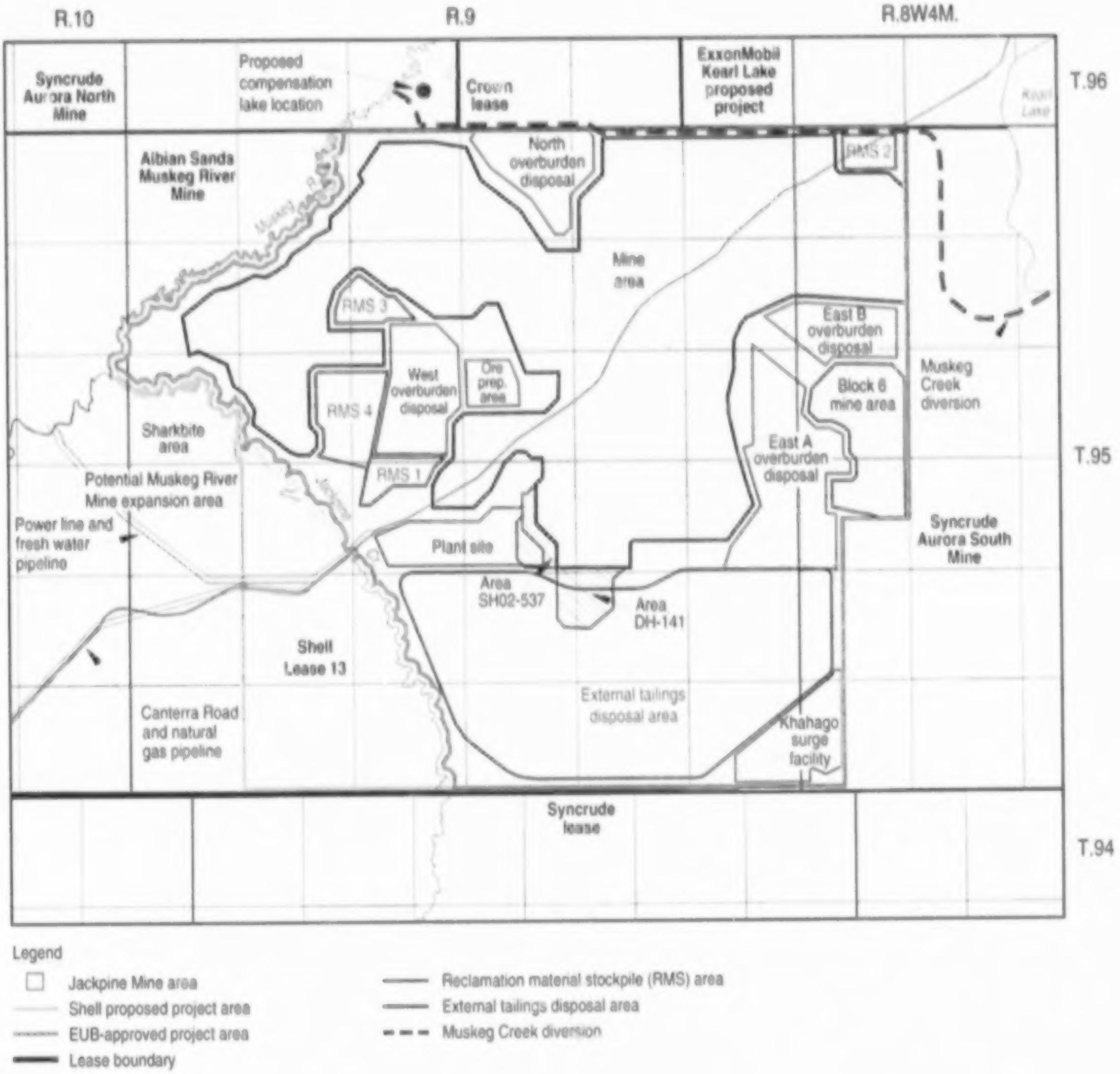
R.10
R.9
R.8W4M.
T.96
T.95
T.94
Syncrude Aurora North Mine
Proposed compensation lake location
Crown lease
ExxonMobil Kearl Lake proposed project
Kearl Lake
Albian Sands Muskeg River Mine
Muskeg River
North overburden disposal
RMS 2
Mine area
RMS 3
West overburden disposal
Ore prep. area
RMS 4
RMS 1
East B overburden disposal
Block 6 mine area
Muskeg Creek diversion
East A overburden disposal
Sharkbite area
Potential Muskeg River Mine expansion area
Jackpine Creek
Power line and fresh water pipeline
Plant site
Syncrude Aurora South Mine
Area SH02-537
Area DH-141
Shell Lease 13
External tailings disposal area
Canterra Road and natural gas pipeline
Khahago surge facility
Syncrude lease
Legend
Jackpine Mine area
Shell proposed project area
EUB-approved project area
Lease boundary
Reclamation material stockpile (RMS) area
External tailings disposal area
Muskeg Creek diversion

Figure 1. Shell Jackpine Mine and surrounding area

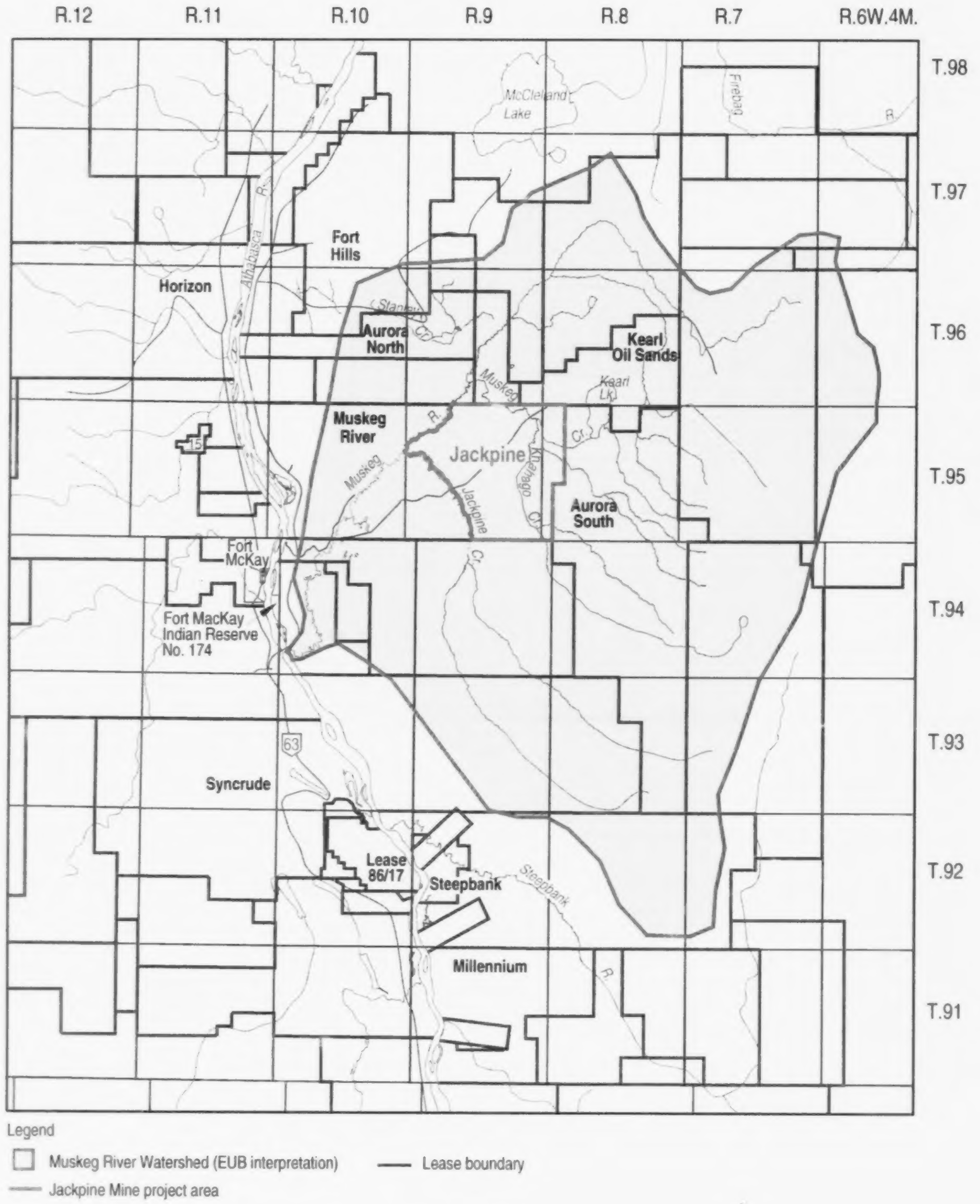
R.12
R.11
R.10
R.9
R.8
R.7
R.6W.4M.
T.98
T.97
T.96
T.95
T.94
T.93
T.92
T.91
McClelland Lake
Firebag
R.
Athabasca
R.
Fort Hills
Horizon
Stanley Cr.
Aurora North
Kearl Oil Sands
Kearl Lk.
Muskeg
Muskeg River
Jackpine
Muskeg
R.
Khahago Cr.
Cr.
Jackpine Cr.
Aurora South
15
Fort McKay
Fort MacKay Indian Reserve No. 174
63
Syncrude
Lease 86/17
Steepbank
Steepbank
Millennium
R.
Legend
Muskeg River Watershed (EUB interpretation)
Lease boundary
Jackpine Mine project area

Figure 2. Muskeg River watershed